UNITED STATES
DEPARTMENT OF THE INTERIOR

FINAL

ENVIRONMENTAL STATEMENT

VOLUME 3 OF 3

PROPOSED
INCREASE IN OIL AND GAS LEASING
ON THE OUTER CONTINENTAL SHELF

FES 75 -

Prepared by the

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PART 250 — OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

AUTHORITY: The provisions of this Part 250 issued under secs. 5, 6, 67 Stat. 464, 465; 43 U.S.C. 1334, 1335.

SOURCE: The provisions of this Part 250 appear at 19 F.R. 2656, May 8, 1954, unless otherwise noted.

CROSS REFERENCE: For further regulations pertaining to the issuance and recognition of mineral leases covering submerged lands in the Outer Continental Shelf, see 43 CFR Part 3300.

GENERAL PROVISIONS

§250.1 Purpose and authority.

The Outer Continental Shelf Lands Act enacted on August 7, 1953 (67 Stat. 462), referred to in this part as "the act," authorizes the Secretary of the Interior at any time to prescribe and amend such rules and regulations, to be applicable to all operations conducted under a lease issued or maintained under

the provisions of the act, as he determines to be necessary and proper to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. Subject to the supervisory authority of the Secretary of the Interior, the regulations in this part shall be administered by the Director of the Geological Survey through the Chief, Conservation Division. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.2 Definitions.

The following terms as used in the regulations in this part shall have the meanings here given:

(a) *Secretary.* The Secretary of the Interior.

(b) *Director.* The Director of the Geological Survey, Washington, D.C., having direction of the enforcement of the regulations in this part. [As amended at 38 F.R. 10003, April 23, 1973.]

(c) *Supervisor.* The Area Oil and Gas Supervisor, Conservation Division of the Geological Survey; a representative of the Secretary, subject to the direction and supervisory authority of the Director, through the Chief, Conservation Division, Geological Survey, and the appropriate Conservation Manager, Conservation Division, Geological Survey, authorized and empowered to regulate operations and to perform other duties prescribed in the regulations in this part, or any subordinate of such representative acting under his direction. [As amended at 38 F.R. 10003, April 23, 1973.]

(d) *Outer Continental Shelf.* All submerged lands (1) which lie seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29) and (2) of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(e) *Lease.* The contract or agreement under which the leasehold rights are held by the lessee, or the land covered by the contract or agreement, whichever is required by the context.

(f) *Lessee.* The party authorized by a lease, or an approved assignment thereof, to develop and produce the leased deposits in accordance with the regulations in this part, including all parties holding such authority by or through him.

(g) *Operator.* The individual, partnership, firm, or corporation having control or management of operations on the leased land or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(h) *Waste of oil and gas.* Waste means and includes (1) physical waste as that term is generally understood in the oil and gas industry; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner which causes or tends to cause reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; (4) the inefficient storage of oil; and (5) the production of oil or gas in excess of transportation or marketing facilities or in excess of reasonable market demand.

(i) *Directional drilling.* The deviation of a bore hole from the vertical or from its normal course in an intended predetermined direction or course with respect to the points of the compass. Directional drilling shall not include deviations made for the purpose of straightening a hole that has become crooked in a normal course of drilling or deviating a hole at random without regard to compass direction in an attempt to sidetrack a portion of the hole on account of mechanical difficult in drilling.

(j) *OCS Order.* A formal numbered order issued by the supervisor and available in his office, with the prior approval of the Chief, Conservation Division, Geological Survey, that implements the regulations in this part and applies to operations in a region or a major portion thereof.

(k) *Pollution Contingency Plan.* The National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan cosigned by the Department of the Interior, Department of Transportation, Department of Defense, Department of Health, Education, and Welfare, and the Office of Emergency Preparedness and administered by the Secretary of the Interior, or any successor plan thereto. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.10 Jurisdiction.

Subject to the supervisory authority of the Secretary and the Director, drilling and production operations, handling, and measurement of production, determination and collection of rental and royalty, and in general, all operations conducted on a lease by or on behalf of a lessee are subject to the regulations in this part, and are under the jurisdiction of the Supervisor for any area as delineated by the Director. In the exercise of this jurisdiction, the Supervisor shall be subject to the direction and supervisory authority of the Chief, Conservation Division, and the appropriate Conservation Manager, Conservation Division, Geological Survey, each of whom may exercise the jurisdiction of the Supervisor. [As amended at 30 F.R. 10003, Apr. 23, 1973.]

§250.11 General functions.

The supervisor is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this part and to require compliance with applicable laws, the lease terms, applicable regulations, and OCS Orders to the end that all operations shall be conducted in a manner which will protect the natural resources of the Outer Continental Shelf and result in the maximum economic recovery of the mineral resources in a manner compatible with sound conservation practices. Subject to the approval of the Chief, Conservation Division, Geological Survey, the supervisor may issue OCS Orders implementing the requirements of the regulations of this part when such implementations apply to an entire region or a major portion thereof. The supervisor may issue written or oral orders to govern lease operations. Oral orders shall be confirmed in writing by the supervisor as promptly as possible. The supervisor may issue other orders, and rules to govern the development and method of production of a pool, field, or area. Prior to the issuance of OCS Orders and other orders and rules, the supervisor may consult with, and receive comments from, lessees, operators, and other interested parties. Before permitting operations on the leased land, the supervisor may require evidence that a lease is in good standing, that the lessee is authorized to conduct operations, and that an acceptable bond has been filed. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.12 Regulation of operations.

(a) *Duties of supervisor.* The supervisor in accordance with the regulations in this part shall inspect and regulate all operations and is authorized to issue OCS Orders and other orders and rules necessary for him to effectively supervise operations and to prevent damage to, or waste of, any natural resource, or injury to life or property. The supervisor shall receive, and shall, when in his judgment it is necessary, consult with or solicit advice from lessees, field officials of interested Departments and agencies, including the Fish and Wildlife Service, Federal Water Pollution Control Administration, Bureau of Land Management, Coast Guard, Department of Defense, Corps of Engineers, and representatives of State and local governments.

(b) *Departures from orders.* (1) The supervisor may prescribe or approve in writing, or orally with written confirmation, minor departures from the requirements of OCS Orders and other orders and rules issued pursuant to (a) of this section, when such departures are necessary for the proper control of a well, conservation of natural resources, protection of aquatic life, protection of human health and safety, property, or the environment.

(2) All requests or recommendations for major departures from the requirements of OCS Orders, whether on an individual well or field basis, shall be approved by the Chief, Conservation Division.

(c) *Emergency suspensions.* The supervisor is authorized, either in writing or orally with written confirmation, to suspend any operation, including production, which in his judgment threatens immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to the leased deposits, to other valuable mineral deposits or to the environment. Such emergency suspension shall continue until in his judgment the threat or danger has terminated.

(d) *Other suspensions.* (1) In addition to the provisions of section 12 (c) and (d) of the act providing for suspension of operations and production, in the interest of conservation the supervisor may direct or, at the request of a lessee, may approve the suspension of operations or production, or both, including the approval of suspension of production for (i) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities and thereafter temporarily abandoned or permanently plugged and abandoned to facilitate proper development of the lease, and (ii) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities, but which cannot be produced because of the lack of transportation facilities. Suspensions of operations or production, or both, may be approved for an initial period, not exceeding 2 years, and for succeeding periods, not exceeding 1 year each.

(2) As to any leases maintained under section 6 of the act covering minerals in addition to oil and gas, the supervisor may suspend operations separately as to oil and gas or as to any other mineral designated in the suspension, order, or grant.

(3) The supervisor is authorized by written notice to the lessee to suspend any operation, including production, for failure to comply with applicable law, the lease terms, the regulations in this part, OCS Orders, or any other written order or rule including orders for filing of reports and well records or logs within the time specified.

(e) ***Reduction of rental and royalty.*** In order to increase the ultimate recovery of minerals and in the interest of conservation, the Director of the Geological Survey, whenever he determines it necessary to promote development or finds that a lease cannot be successfully operated under the terms provided therein, may reduce the rental, minimum royalty, or royalty on the entire leasehold, or on any deposit, tract, or portion thereof segregated for royalty purposes. An application for any of the above relief shall be filed in triplicate with the Director of the Geological Survey. It must contain the serial number of the lease; the name of the record title holder; a description of the area

included in the lease; the number, location, and status of each well that has been drilled; a tabulated statement for each month, covering a period of not less than 6 months prior to the date of filing the application, of the aggregate amount of minerals subject to royalty computed in accordance with the lease and applicable regulations. Every application must also contain a detailed statement of expenses and costs of operating the entire lease and of the income from the sale of any leased products, and all facts tending to show whether the wells or workings can be successfully operated upon the rental or royalty fixed in the lease. Where the application is for a reduction of royalty, full information shall be furnished as to whether royalties or payments out of production are paid to others than the United States, the amounts so paid, and efforts made to reduce them. The applicant must also file agreements of the holders of the lease and of royalty holders to a permanent reduction of all other royalties from the leasehold to an aggregate not in excess of one half the Government royalties. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.13 Temporary approvals.

Whenever the regulations in this part require a lessee to obtain approval of the supervisor, the lessee may make an oral or telegraphic request for such approval, and the supervisor may give such oral or telegraphic approval as may be warranted: *Provided*, That the transaction shall forthwith be confirmed in the manner otherwise required by the regulations in this part.

§250.14 Samples, tests, and surveys.

(a) When deemed necessary or advisable, the supervisor is authorized to require that adequate tests or surveys be made in an acceptable manner without cost to the lessor to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The supervisor may, at the time of approval of any notice to drill or redrill any well, stipulate reasonable requirements for the taking of formation samples or cores to determine the identity and character of any formation.

§250.15 Drilling and abandonment of wells.

The supervisor shall demand drilling in accordance with the terms of the lease and of the regulations in this part; and shall require plugging and abandonment, in accordance with such plan as may be approved or prescribed by him, of any well no longer used or useful, and upon failure to secure compliance with such requirement, perform the work at the expense of the lessee, expending available public funds, and submit such report as may be needed to furnish a basis for appropriate action to obtain reimbursement.

§250.16 Well potentials and permissible flow.

The supervisor is authorized to specify the time and method for determining the potential capacity of any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established by the Secretary.

§250.17 Well locations and spacing.

The supervisor is authorized to approve well locations and well spacing programs necessary for proper development giving consideration to such factors as the location of drilling platforms, the geological and reservoir characteristics of the field, the number of wells that can be economically drilled, the protection of correlative rights, and minimizing unreasonable interference with other uses of the Outer Continental Shelf area. [As amended and renamed "Well Locations and Spacing" from "Well Spacing and Well Casing" at 34 F.R. 13544, Aug. 22, 1969.]

§250.18 Rights of use and easement.

(a) In addition to the rights and privileges granted to a lessee under any lease issued or maintained under the act, the supervisor may grant such lessee, subject to such reasonable conditions as said supervisor may prescribe, the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands, and to use the same for carrying on operations, including drilling, directional drilling, producing, treating, handling, and storing production, and housing personnel engaged in operations, not only in connection with the lease on which the platform, structure, or island, is situated, but for the conduct of operations on any other lease, State or Federal.

(b) The supervisor may grant to a holder of a Federal or State lease the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands on areas of the Outer Continental Shelf, near or adjacent to the leased area, and to use same for drilling directional well or wells to be bottomed under the leased area, and for producing and reworking such well or wells, and for handling, treating, and storing the production therefrom. Such rights of use or easement if on an area subject to any mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified and afforded an opportunity to voice objections thereto, and any such right shall be exercised only in such manner so as not to interfere unreasonably with operations of the lessee under such lease.

(c) In addition to the rights and privileges granted to a Federal lessee under any lease issued or maintained under the act, the supervisor upon proper

application may grant to a holder of a Federal lease or State lease issued by a State which extends the same rights to holders of Federal leases, subject to such reasonable conditions as the supervisor may prescribe, the right of use or an easement to construct and maintain pipelines on areas of the Outer Continental Shelf which are constructed, owned, and maintained by the lessee and used for purposes such as (1) moving production to a central point for gathering, treating, storing, or measuring; (2) delivery of production to a point of sale; (3) delivery of production to a pipeline operated by a transportation company; or (4) moving fluids in connection with lease operations, such as for injection purposes. The supervisor is authorized to approve any reasonable offshore or onshore location as the central or delivery point. Rights of use or easement across areas covered by a mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified by the applicant and afforded a reasonable opportunity to express its views with respect thereto, and any such rights shall be exercised only in a manner so as not to interfere unreasonably with operations of the lessee under such lease. The foregoing right of use and easement shall not apply to pipelines used for transporting oil, gas, or other production after custody has been transferred to a purchaser or carrier as provided for in section 5(c) of the Outer Continental Shelf Lands Act and regulations in 43 CFR 2234 5-3. [Now 43 CFR 2883.]

(d) Once a right of use or easement has been exercised by the erection of platforms, fixed structures, artificial islands, or pipelines, the right shall continue only so long as they are maintained and are useful for the purpose specified therein, as determined by the supervisor, even beyond the termination of any lease on which they may be situated, and the rights of all subsequent lessees shall be subject to such rights of use and easement by prior lessees. Upon termination by the supervisor of the right of use and easement, the lessee shall remove or otherwise dispose of all platforms, fixed structures, artificial islands, pipelines, and other facilities and restore the premises to the satisfaction of the supervisor; provided, however, that pipelines may be abandoned in place for so long as they do not constitute a navigational or other hazard as determined by the supervisor. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.19 Platforms and pipelines.

(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraphs (a) or (b) of §250.18 or authorized under any lease issued or maintained under the act.

(b) The supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of §250.18 or authorized under any lease issued or maintained under the act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.20 Rentals, royalties, and other payments.

The supervisor shall determine pursuant to the lease and regulations the rental and the amount or value of production accruing to the lessor as royalty, the loss through waste or failure to drill and produce protection wells on the lease, and the compensation due to the lessor as reimbursement for such loss. [250.20 is revoked and 250.19 is redesignated as 250.20 at 34 F.R. 13544, Aug. 22, 1969.]

REQUIREMENTS FOR LESSEES

§250.30 Lease terms, regulations, waste, damage, and safety.

The lessee shall comply with the terms of applicable laws and regulations, the lease terms, OCS Orders and other written orders and rules of the supervisor, and with oral orders of the supervisor. All such oral orders shall be effective when issued, and are to be confirmed in writing as provided in §250.11. The lessee shall take all necessary precautions to prevent damage to or waste of any natural resource or injury to life, or property, or the aquatic life of the seas. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.31 Designation of operator.

In all cases where operations are not conducted by the record owner but are to be conducted under authority of an unapproved operating agreement, assignment, or other arrangement, a "designation of operator" shall be submitted to the supervisor, in a manner and form approved by him, prior to commencement of operations. Such designation will be accepted as authority of operator or his local representative to fulfill the obligations of the lessee and to sign any papers or reports required under the regulations in this part. All changes of address and any termination of the authority of the operator shall be immediately reported, in writing, to the supervisor or his representative. In case of such termination or controversy between the lessee and the designated operator, the operator, if in possession of the lease, will be required to protect the interests of the lessor.

§250.32 Local agent.

When required by the supervisor, the lessee shall designate a representative empowered to receive notices and comply with orders of the supervisor issued pursuant to the regulations in this part.

§250.33 Drilling and producing obligations.

(a) The lessee shall diligently drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties, or in lieu thereof, with the consent of the supervisor, shall pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

(b) The lessee shall promptly drill and produce such other wells as the supervisor may reasonably require in order that the lease may be properly and timely developed and produced in accordance with good operating practices.

§250.34 Drilling and development programs.

(a) *Exploratory drilling plan.* Prior to commencing each exploratory drilling program on a lease, including the construction of platforms, the lessee shall submit a plan to the supervisor for approval. Each plan for the leased area shall include (1) a description of drilling vessels, platforms, or other structures showing the location, the design, and the major features thereof, including features pertaining to pollution prevention and control; (2) the general location of each well including surface and projected bottom hole location for directionally drilled wells; (3) structural interpretations based on available geological and geophysical data, and (4) such other pertinent data as the supervisor may prescribe.

(b) *Development plan.* Prior to commencing each development program on a lease, the lessee shall submit a plan to the supervisor for approval. The plan shall include all information specified in paragraph (a) of this section in detail.

(c) *Drilling applications.* Prior to commencing drilling operations either under an exploratory or development plan, the lessee shall submit an Application for Permit to Drill (Form 9-331C) to the supervisor for approval. The application shall include the integrated blowout prevention, mud, casing, and cementing program for the well, and shall meet the requirements specified in §250.41(a), and contain the information specified in §250.91(a), and shall conform with the approved exploratory or development plan.

(d) *Modifications.* The lessee shall submit: (1) All requests for modifications of an approved exploratory or development plan in writing to the supervisor for approval; and (2) all notices of changes to plans set forth in the approved Application for Permit to Drill on Sundry Notices and Reports on Wells (Form 9-331), except that these requirements shall not relieve the lessee from taking appropriate action to prevent or abate damage, waste, or pollution of any natural resource or injury to life or property. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.35 Extension of leases by drilling or well reworking.

(a) The Secretary shall be deemed to have approved, within the meaning of section 8(b)(2) of the Outer Continental Shelf Lands Act, drilling or well reworking operations, conducted on the leased area in the following instances:

(1) If, after discovery of oil or gas in paying quantities has been made on the leasehold and within 90 days prior to expiration of the five-year term or any extension thereof, or thereafter, the production thereof shall cease at any time, or from time to time, from any cause and production is restored or drilling or well reworking operations are commenced within 90 days thereafter, and such drilling or well reworking operations (whether on the same or different wells) are prosecuted diligently until production is restored in paying quantities.

(2) If, within 90 days prior to expiration of the five-year term or any extension thereof, or thereafter, at any time, or from time to time, lessee is engaged in drilling or well reworking operations on the leasehold and there is no well on the leasehold capable of producing in paying quantities and the lessee diligently prosecutes such operations (whether on the same or different wells) with no cessation of more than 90 days.

(b) The Secretary may approve such other operations for drilling or reworking upon application of lessee.

(c) Nothing in this section obviates the necessity of obtaining the supervisor's approval of a plan or notice of intention to drill or of complying with the other provisions of this part. [24 F.R. 9527. Nov. 28, 1959; as redesignated from 250.34a at 34 F.R. 13544, Aug. 22, 1969.]

§250.36 Subsequent well operations.

Prior to commencing operations not previously approved, such as deepening, plugging-back, repairing (other than work incidental to ordinary well operations), acidizing or stimulating production by other methods, perforating, sidetracking, squeezing with mud or cement, abandoning, and any similar operation which will alter the condition of a well, the lessee shall submit an application or notice as specified in §250.91 and 250.92 to the supervisor for approval.

This requirement shall not relieve the lessee from taking appropriate action to prevent or abate damage or waste of any natural resource, or injury to life or property. [As amended and redesignated from 250.35 at 34 F.R. 13544, Aug. 22, 1969.]

§250.37 Well designations.

The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings. [As redesignated from 250.36 at 34 F.R. 13544, Aug. 22, 1969.]

§250.38 Well records.

(a) The lessee shall keep for each well at his field headquarters or at other locations conveniently available to the supervisor, accurate and complete records of all well operations including production, drilling, logging, directional well surveys, casing, perforating, safety devices, redrilling, deepening, repairing, cementing, alterations to casing, plugging, and abandoning. The records shall contain a description of any unusual malfunction, condition or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits, and water in each formation; the kind, weight, size, grade, and setting depth of casing; and any other pertinent information.

(b) Upon request of the supervisor, the lessee shall immediately transmit copies of records of any of the well operations specified in paragraph (a) of this section; however, in any event the lessee shall, within 30 days after completion of any well, transmit to the supervisor copies of the records of all operations (except logging) in duplicate on or attached to Form 9-330, except that when operations are suspended the lessee shall transmit copies of the records of all operations conducted thereon to the supervisor within 30 days after the suspension; and within 30 days after the suspension or completion of any further operations, including those described in §250.92, the lessee shall transmit to the supervisor copies of the records of such operations in duplicate on or attached to Form 9-330 or Form 9-331, as appropriate.

(c) Upon request by the supervisor, the lessee shall submit paleontological reports identifying microscopic fossils by depth (not the resulting interpretations based upon such identifications) unless washed well samples normally maintained by the lessee for paleontological determinations are made available to the supervisor for inspection.

(d) Upon request of the supervisor, the lessee shall immediately transmit copies (field or final prints of individual runs) of logs or charts of electrical, radioactive, sonic, and other well logging operations and directional well surveys. Composite logs of multiple runs and directional well surveys shall be transmitted to the supervisor in duplicate as soon as available, but not later than 30 days after completion of such operations for each well.

(e) Upon request of and in the manner and form prescribed by the supervisor, the lessee shall furnish copies of the daily drilling report and a plat showing the location, designation, and status of all wells on the leased lands.

(f) Upon request of the supervisor, the lessee shall furnish legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, or other similar services.

(g) The lessee shall submit any other reports and records of operations when required and in the manner and form prescribed by the supervisor. [As amended and redesignated from 250.37 at 34 F.R. 13544, Aug. 22, 1969.]

§250.39 Samples, tests, and surveys.

(a) The lessee, when required by the supervisor, shall make adequate tests or surveys in an acceptable manner, without cost to the lessor, to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The lessee shall take such formation samples or cores to determine the identity and character of any formation in accordance with reasonable requirements of the supervisor prescribed at the time of approval of the notice to drill or redrill any well. [As redesignated from 250.38 at 34 F.R. 13544, Aug. 22, 1969.]

§250.40 Directional survey.

(a) An angular deviation and directional survey shall be made of the finished hole of each well directionally drilled.

(b) The supervisor, at the request of an offset lessee made prior to completion of a well, may require a lessee of an adjoining lease to make or furnish a directional survey of any hole, at the risk and expense of the offset lessee making such request. A copy of such directional survey shall be furnished to the supervisor and the offset lessee. If it is determined that such well is closer to the line of the offset lease than one-half (1/2) the required distance from such line fixed by an approved spacing program or by special field rules, the risk and expense of making such

directional survey shall be borne by the offending lessee; and, unless and until the hole is promptly straightened to correct the offense, the supervisor may reduce the allowable production from the well to prevent its draining unduly the offset leased area. Neither the imposition of any penalty or of the costs of such survey upon the offending lessee nor the reduction of the allowable production from the well is intended to prejudice any other remedy which the affected parties may have. [As redesignated from 250.39 at 34 F.R. 13544, Aug. 22, 1969.]

§250.41 Control of wells.

(a) *Drilling wells.* The lessee shall take all necessary precautions to keep all wells under control at all times, shall utilize only personnel trained and competent to drill and operate such wells, and shall utilize and maintain materials and high-pressure fittings and equipment necessary to insure the safety of operating conditions and procedures. The design of the integrated casing, cementing, drilling mud, and blowout prevention program shall be based upon sound engineering principles, and must take into account the depths at which various fluid or mineral-bearing formations are expected to be penetrated, and the formation fracture gradients and pressures expected to be encountered, and other pertinent geologic and engineering data and information about the area.

(1) *Well casing and cementing.* The lessee shall case and cement all wells with a sufficient number of strings of casing in a manner necessary to: (i) Prevent release of fluids from any stratum through the well bore (directly or indirectly) into the sea; (ii) prevent communication between separate hydrocarbon-bearing strata (except such strata approved for commingling) and between hydrocarbon and water-bearing strata; (iii) prevent contamination of fresh water strata, gas, or water; (iv) support unconsolidated sediments; and (v) otherwise provide a means of control of the formation pressures and fluids. The lessee shall install casing necessary to withstand collapse, bursting, tensile, and other stresses and the casing shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well. When directed by the supervisor, the lessee shall install structural or drive casing to provide hole stability for the initial drilling operation. A conductor string of casing (the first string run other than any structural or drive casing) must be cemented with a volume of cement sufficient to circulate back to the sea floor; however, if authorized by OCS Order or the supervisor, cement may be washed out or displaced to a specified depth below the sea floor to facilitate casing removal upon well abandonment. All subsequent strings must be securely cemented.

(2) *Drilling mud.* The lessee shall maintain readily accessible for use quantities of mud sufficient to insure well control. The testing procedures, characteristics, and use of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent blowouts. Mud testing equipment and mud volume measuring devices shall be maintained at all times, and mud tests shall be performed frequently and recorded on the driller's log as prescribed by the supervisor.

(3) *Blowout prevention equipment.* The lessee shall install, use, and test blowout preventers and related well-control equipment in a manner necessary to prevent blowouts. Such installation, use and testing must meet the standards or requirements prescribed by the supervisor; provided, however, in no event shall the lessee conduct drilling below the conductor string of casing until the installation of at least one remotely controlled blowout preventer and equipment for circulating drilling fluid to the drilling structure or vessel. Blowout preventers and related well-control equipment shall be pressure tested when installed, after each string of casing is cemented, and at such other times as prescribed by the supervisor. Blowout preventers shall be activated frequently to test for proper functioning as prescribed by the supervisor. All blowout-preventer tools shall be recorded on the driller's log.

(b) *Completed wells.* In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) In wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor. [As amended at 25 F.R. 637, Jan. 26, 1960. As amended and redesignated from 250.40 at 34 F.R. 13544, Aug. 22, 1969.]

§250.42 Emulsion and dehydration.

(a) The lessee shall complete and maintain all oil wells in such mechanical condition and operate them in such manner as to prevent, so far as possible, the formation of emulsion and basic sediment.

(b) The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment. [Redesignated from 250.41 at 34 F.R. 13544, Aug. 22, 1969.]

§250.43 Pollution and waste disposal.

(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous

matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and nonliquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with paragraph (b) of this section shall be governed by applicable law. [As amended at 34 F.R. 2503, Feb. 21, 1969, and amended and redesignated from 250.42 at 34 F.R. 13544, Aug. 22, 1969.]

§250.44 Well abandonment.

The lessee shall promptly plug and abandon any well on the leased land that is not used or useful, but no productive well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the supervisor. Before abandoning a producible well, the lessee shall submit to the supervisor a statement of reasons for abandonment and his detailed plans for carrying on the necessary work. A producible well may be abandoned only after receipt of written approval by the supervisor. No well shall be plugged and abandoned until the manner and method of plugging shall be approved or prescribed by the supervisor. Equipment shall be removed, and premises at the well-site shall be properly conditioned immediately after plugging operations are completed on any well when directed by the supervisor. Drilling equipment shall not be removed from any suspended drilling well without taking adequate measures to protect the natural resources. [As redesignated from 250.43 at 34 F.R. 13544, Aug. 22, 1969.]

§250.45 Accidents, fires, and malfunctions.

In the conduct of all its operations, the lessee shall take all steps necessary to prevent accidents and fires, and the lessee shall immediately notify the supervisor of all serious accidents and all fires on the lease, and shall submit in writing a full report thereon within 10 days. The lessee shall notify the supervisor within 24 hours of any other unusual condition, problem, or malfunction. [As amended and redesignated from 250.44 at 34 F.R. 13544, Aug. 22, 1969.]

§250.46 Workmanlike operations.

The lessee shall perform all operations in a safe and workmanlike manner and shall maintain equipment for the protection of the lease and its improvements, for the health and safety of all persons, and for the preservation and conservation of the property and the environment. The lessee shall take all necessary precautions to prevent and shall immediately remove any hazardous oil and gas accumulations or other health, safety or fire hazards. [As amended and redesignated from 250.45 at 34 F.R. 13544, Aug. 22, 1969.]

§250.47 Sales contracts.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of all contracts for the disposal of lease products. Nothing in any such contract shall be construed or accepted as modifying any of the provisions of the lease, including provisions relating to gas waste, taking royalty in kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the regulations applicable to the lands covered by the contract. [As amended and redesignated from 250.46 at 34 F.R. 13544, Aug. 22, 1969.]

§250.48 Division orders.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of division orders or other instruments granting to transportation agencies or purchasers authority to receive products from leased lands. The supervisor may, upon request, approve such orders or other instruments subject to such conditions as he shall prescribe. [As amended and redesignated from 250.47 at 34 F.R. 13544, Aug. 22, 1969.]

§250.49 Royalty and rental payments.

The lessee shall pay all rentals when due and shall pay in value or deliver in production all royalties in

the amounts determined by the supervisor as due under the terms of the lease. Payments of rentals and royalties in value shall be by check or draft on a solvent bank, or by money order, drawn to the order of the United States Geological Survey. [As amended at 21 F.R. 4668, June 27, 1956, and redesignated from 250.48 at 34 F.R. 13544, Aug. 22, 1969.]

§250.50 Unit plans, pooling, and drilling agreements.

Section 5(a)(1) of the act authorizes the Secretary in the interest of conservation to provide for unitization, pooling and drilling agreements. Such agreements may be initiated by lessees or where in the interest of conservation they are deemed necessary they may be required by the Director. [Section 3381.1 of 43 CFR is amended and redesignated 250.50 at 34 F.R. 13544, Aug. 22, 1969.]

§250.51 Application for approval of unit plan.

The procedure for obtaining the approval of a unit plan of development is contained in 30 CFR Part 226. "Unit or Cooperative Agreements." All applications to unitize and all documents incident thereto shall be filed in the office of the oil and gas supervisor, Geological Survey, for the geographic area in which the unit is situated. [Section 3381.1 of 43 CFR is amended and redesignated 250.51 at 34 F.R. 13544, Aug. 22, 1969, also, as amended at 38 F.R. 10003, Apr. 23, 1973.]

§250.52 Pooling or drilling agreements.

(a) With the approval of the supervisor, pooling or drilling agreements may be made between lessees for the purposes of (1) utilizing a common drilling platform to develop adjacent or adjoining leases; (2) permitting operators or pipeline companies to enter into contracts involving a number of leases sufficient to justify operations on a large scale for the discovery, development, production or transportation of oil and gas, sulphur, or other minerals and to finance the same; or (3) for other purposes in the interest of conservation.

(b) A contract submitted for approval under these provisions should be filed with the oil and gas supervisor, together with enough copies to permit retention of 5 copies by the Department after approval. Complete details must be furnished in order that the supervisor may have facts upon which to make a definite determination and prescribe the conditions on which the contract is approved. [Section 3381.3 of 43 CFR is amended and redesignated 250.52 at 34 F.R. 13544, Aug. 22, 1969.]

§250.53 Subsurface storage of oil or gas.

(a) In order to avoid waste or to promote conservation of natural resources, and when it can be shown that no undue intereference with operations under existing leases will result, the Director, upon application by the interested parties, may authorize the subsurface storage of oil or gas in the lands of the Outer Continental Shelf, whether or not produced from the Outer Continental Shelf. Such authorization will provide for the payment of such storage fee or rental on the stored oil or gas as may be determined adequate in each case, or, in lieu thereof, for a royalty other than that prescribed in any lease of the area involved when such stored oil or gas is produced in conjunction with oil or gas not previously produced. Any lease of an area used for the storage of oil or gas shall not be deemed to expire during the period of such storage and so long thereafter as oil or gas not previously produced in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted thereon.

(b) Applications for subsurface storage shall be filed in triplicate with the oil and gas supervisor and shall disclose the ownership of the lands or interests in the lands involved, the parties in interest, including lessees of other mineral interests, the storage fee, rental, or royalty offered to be paid for such storage and all essential information showing the necessity for such storage. Enough copies of the final agreement signed by the parties in interest shall be submitted for the approval of the Director to permit retention of 5 copies by the Department after approval. [Section 3381.4 of 43 CFR is amended and redesignated 250.53 at 34 F.R. 13544, Aug. 22, 1969.]

MEASUREMENT OF PRODUCTION AND COMPUTATION OF ROYALTIES

§250.60 Measurement of oil.

The lessee shall gage and measure all production in accordance with methods approved by the supervisor. The lessee shall provide tanks suitable for measuring accurately the crude oil produced from the lease (exact copies of 100 percent capacity tank tables to be furnished to the supervisor) or may arrange with the supervisor for other acceptable methods of measuring, storing, and recording production. The quantity and quality of all production shall be determined in accordance with the standard practices, procedures, and specifications generally used by the industry. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.61 Measurement of gas.

The lessee shall measure all gas production in accordance with methods approved by the supervisor, and the measured volumes shall be adjusted to the standard pressure base of 10 ounces above the atmospheric pressure of 14.4 pounds per square inch, a standard temperature of 60° Fahrenheit, and for deviation from Boyle's law. If gas is being disposed of at a different pressure base, the supervisor may require that gas volumes be adjusted to conform to such base.

§250.62 Determination of content of gas.

The content of gas delivered to an extraction plant treating gas from the lease shall be determined periodically by field tests, as required by the supervisor, to be made at the place and by the methods approved by him and under his supervision.

§250.63 Quantity basis for substances extracted from gas.

(a) The primary quantity basis for computing monthly royalties on casing-head or natural gasoline, butane, propane, or other substances (hereinafter called substances in this section) extracted from gas is the monthly net output of the plant at which the substances are manufactured, "net output" being defined as the quantity of each substance that the plant produces for sale.

(b) If the net output of a plant is derived from the gas obtained from only one lease, the quantity of substances on which computations of royalty for the lease is based is the net output of the plant.

(c) If the net plant output of a substance is derived from gas obtained from several leases producing gas of uniform content of such substance, the proportion of net output of the substance allocable to each lease as a basis for computing royalty will be determined by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(d) If the net plant output of a substance is derived from gas obtained from several leases producing gas of diverse content of such substance, the proportion of net output of the substance allocable to each lease as a basis for computing royalty will be determined by multiplying the amount of gas delivered to the plant from the lease by the substance content of the gas and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant.

§250.64 Value basis for computing royalties.

The value of production, for the purpose of computing royalty, shall be the estimated reasonable value of the product as determined by the supervisor, due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field or area, to the price received by the lessee, to posted prices, and to other relevant matters. Under no circumstances shall the value of production of any of said substances for the purposes of computing royalty be deemed to be less than the gross proceeds accruing to the lessee from the sale thereof or less than the value computed on such reasonable unit value as shall have been determined by the Secretary. In the absence of good reason to the contrary, value computed on the basis of the highest price paid or offered at the time of production in a fair and open market for the major portion of like-quality products produced and sold from the field or area where the leased lands are situated will be considered to be a reasonable value.

§250.65 Royalty on oil.

(a) The royalty on crude oil, including condensates separated from gas without the necessity of a manufacturing process, shall be the percentage of the value or amount of the crude oil produced from the leased lands established by law, regulation, or the provisions of the lease. No deduction shall be made for actual or theoretical transportation losses.

(b) Royalty shall be based on production removed from the lease except that, when conditions so warrant, the supervisor may require such royalty to be based on actual monthly production. Evidence of all shipments shall be filed with the supervisor within five days (or such longer period as the supervisor may approve) after the oil has been run by pipeline or by other means of transportation. Such evidence shall be signed by representatives of the lessee and of the purchaser or the transporter who have witnessed the measurements reported, and the determinations of gravity, temperature, and the percentage of impurities contained in the oil shall be shown. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.66 Royalty on unprocessed gas.

If gas, either gas-well gas or casing-head gas, is sold without processing for the recovery of constituent products, the royalty thereon shall be the percentage established by the terms of the lease of the value or amount of the gas produced.

§250.67 Royalty on processed gas and constituent products.

(a) If gas is processed for the recovery of constituent products, a royalty as provided in the lease will accrue on the value or amount of:

(1) All residue gas remaining after processing; and

(2) All natural gasoline, butane, propane, or other products extracted therefrom, subject to deduction of such portion thereof as the supervisor determines to be a reasonable allowance for the cost of processing based upon regional plant practices and costs and other pertinent factors; provided, however, that such reasonable allowance shall not exceed two-thirds of the products extracted unless the Director determines that a greater allowance is in the interest of conservation.

(b) Under no circumstances shall the amount of royalty on the residue gas and extracted products be

less than the amount which the supervisor determines would be payable if the gas had been sold without processing.

(c) In determining the value of natural gasoline, the volume of such gasoline shall be adjusted to a standard by a method approved by the supervisor when necessary to adjust volumetric differences between natural gasolines of various specifications.

(d) No allowance shall be made for boosting residue gas or other expenses incidental to marketing.

(e) The lessee, with the approval of the supervisor, may establish a gross value per unit of 1,000 cubic feet of gas on the lease or at the wellhead for the purpose of computing royalty on gas processed for the recovery of constituent products, provided that the royalty shall not be less than that which would accrue by computing royalties in accordance with the provisions of paragraph (a) through (d) of this section. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.68 Commingling production.

Subject to such conditions as he may prescribe for measurement and allocation of production, the supervisor may authorize the lessee to move production from the lease to a central point for purposes of treating, measuring, and storing, and in moving such production, the lessee may commingle the production from different wells, leases, pools, and fields, and with production of other operators. The central point may be on shore or at any other convenient place selected by lessee.

§250.69 Measurement of sulphur.

The measurement of sulphur for the purpose of computing royalty shall be on such basis and shall conform to such standards as the supervisor may approve.

PROCEDURE IN CASE OF
DEFAULT BY LESSEE

§250.80 Default.

Whenever the owner of a lease fails to comply with the provisions of the regulations in this part, the supervisor is authorized to give 30-day notice of such default by registered letter to the lessee at his record post office address as provided in section 5(b)(1) of the act and to recommend to the Secretary, through the Director, lease cancellation pursuant to section 5(b)(1) and (2) of the act, appropriate action under the penalty provisions of section 5(a)(2) of the act, or the exercise of such other legal or equitable remedy as the lessor may have.

§250.81 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in part 290 of this chapter. Compliance with any such order or decision shall not be suspended by reason of any appeal having been taken unless such suspension is authorized in writing by the Director or the Board of Land Appeals (depending upon the official before whom the appeal is pending) and then only upon a determination that such suspension will not be detrimental to the lessor or upon the submission and acceptance of a bond deemed adequate to indemnify the lessor from loss or damage. [As amended at 38 F.R. 10004, April 23, 1973.]

§250.82 Judicial review.

Nothing contained in this part shall be construed to prevent any interested party from seeking judicial review as authorized by law.

REPORTS TO BE MADE BY
ALL LESSEES
(Including Operators)

§250.90 General requirements.

Information required to be submitted in accordance with the regulations in this part shall be furnished in the manner and form prescribed in the regulations in this part or as directed by the supervisor. Copies of forms can be obtained from the supervisor and must be filled out completely and filed punctually with that official.

§250.91 Application for permit to drill, deepen, or plug back.

Applications for permits to drill, deepen, or plug back must be filed in triplicate on Form 9-331C. Prior to commencing such operations approval in writing must be received from the supervisor.

(a) *Application for permit to drill.*

(1) The application must give the surface location and projected bottom-hole location in feet from the lease boundaries; elevation of the derrick floor; water depth; depth to which the well is proposed to be drilled; estimated depths to the top of significant markers; depths at which water, oil, gas, and mineral deposits are expected; the proposed blowout prevention and casing program, including the size, weight, grade, and setting depth of casing, and the quantity of cement to be used, together with all other information specified on Form 9-331C. Information also shall be furnished relative to the proposed plan for drilling other wells from the same platform, for coring at specified depths, and for electrical and other

logging, together with any other information required by the supervisor.

(2) At least two copies of the application shall be accompanied by: (i) A certified plat drawn to a scale of 2,000 feet to the inch, showing surface and subsurface location of the well to be drilled and all wells theretofore drilled in the vicinity for which information is available, and (ii) information specified in §250.34 to the extent not included in the application or previously furnished (reference must be made thereto).

(b) *Application for permit to deepen or plug back.* The application must describe fully: (1) The present status of the well including the production string or last string of casing, well depth, present productive zones and productive capability, and other pertinent matters; and (2) the details of the proposed work and the necessity therefor. [As amended and renamed at 34 F.R. 13544, Aug. 22, 1969.]

§250.92 Sundry notices and reports on wells.

All notices of intention to fracture treat, acidize, repair, multiple complete, abandon, change plans, and for other similar purposes, and all subsequent reports pertaining to such operations shall be submitted on Form 9-331 in triplicate in accordance with §250.38(b). Prior to commencing such operations approval must be received from the supervisor in writing.

(a) *Notice of intention to change the condition of a well.* Form 9-331 shall contain a detailed statement of the proposed work for repairing (other than work incidental to ordinary well operation), acidizing or stimulating production by other methods, perforating, sidetracking, squeezing with mud or cement, or commencing any operations that will materially change the approved program for drilling a well or alter the condition of a completed well other than those operations covered by §250.91.

(b) *Subsequent report of changing the condition of a well.* Form 9-331 shall contain a detailed report of all work done and the results obtained. The report shall set forth the amount and rate of production of oil, gas, and water before and after the work was completed and shall include a complete statement of the dates on which the work was accomplished and the methods employed.

(c) *Notice of intention to abandon well.* Form 9-331 shall contain a detailed statement of the proposed work for abandonment of any well, including a drilling well, a depleted producing well, an injection well, or a dry hole. The statement as to a producible well shall set forth the reasons for abandonment and the amount and date of last production and, as to all wells, shall describe the proposed work, including kind, location, and length of plugs (by depths), and plans for mudding, cementing, shooting, testing, removing casing, and other pertinent information.

(d) *Subsequent report of abandonment.* Form 9-331 shall contain a detailed report of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in plugging and the location and extent (by depths) of casing left in the well; and the volume of mud fluid used. If an attempt was made to part any casing, a description of the methods used and results obtained must be included. [As amended and redesignated from 250.91 at 34 F.R. 13544, Aug. 22, 1969.]

§250.93 Monthly report of operations.

A separate report of operations for each lease must be made on Form 9-152 for each calendar month, beginning with the month in which drilling operations are initiated, and must be filed in duplicate with the supervisor on or before the 20th day of the succeeding month, unless an extension of time for the filing of such report is granted by the supervisor. The report on this form shall disclose accurately all operations conducted on each well during each month, the status of operations on the last day of the month, and a general summary of the status of operations on the leased lands, and the report must be submitted each month until the lease is terminated or until omission of the report is authorized by the supervisor. It is particularly necessary that the report shall show for each calendar month:

(a) Each well listed separately by number and its location shown if possible.

(b) The number of days each well produced, whether oil or gas, and the number of days each input well was in operation.

(c) The quantity of oil, gas, and water produced; the total amount of gasoline and other lease products recovered; and other required information. When oil and gas, or oil, gas, and gasoline, or other hydrocarbons are concurrently produced from the same lease, separate reports on this form should be submitted for oil and gas and gasoline, unless otherwise authorized or directed by the supervisor.

(d) The depth of each active or suspended well; the name, character, and depth of each formation drilled during the month; the date each such depth was reached; the date and reason for every shutdown; the names and depths of important formation changes and contents of formations; the amount and size of any casing run since last report; the dates and results of any tests such as production, water shutoff, or gasoline content; and any other noteworthy information on operations not specifically provided for in the form.

(e) If no runs or sales were made during the calendar month, the report must so state.

§250.94 Statement of oil and gas runs and royalties.

When directed by the supervisor, a monthly report shall be made by the lessee in duplicate, on Form 9-153, showing each run of oil; all sales of gas, gasoline, and other lease products; and the royalty accruing therefrom to the lessor. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.95 Well completion or recompletion report and log.

All reports and logs of well completions or recompletions shall be submitted on or attached to Form 9-330 in duplicate in accordance with §250.38(b). The form shall contain a complete and accurate log and report of all operations conducted on the well as specified on the form. Duplicate copies of logs that may have been compiled for geologic information from cores or formation samples shall be filed in addition to the regular log. Geologic markers and all important zones of porosity and contents thereof; cored intervals; and all drill-stem tests, including depth interval tested, cushion used, time tool open, flowing and shut-in pressures, and recoveries shall be shown as provided therefor on Form 9-330 or on attachments thereto. If not previously furnished, duplicate copies of composites of multiple runs of all well bore surveys, including electric, radioactive, sonic and other logs, temperature surveys, and directional surveys shall be attached. (Such copies are in addition to field prints filed pursuant to §250.38(d).) [As amended and redesignated from 250.92 at 34 F.R. 13544, Aug. 22, 1969.]

§250.96 Special forms or reports.

When special forms or reports other than those referred to in the regulations in this part may be necessary, instructions for the filing of such forms or reports will be given by the supervisor. [Redesignated from 250.95 at 34 F.R. 13544, Aug. 22, 1969.]

§250.97 Public inspection of records.

Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area. [F.R. Doc. 69-10027; Filed Aug. 21, 1969.]

MINERAL LEASES AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

§250.100 Effect of regulations on provisions of lease.

(a) As contemplated by section 6(b) of the act, the regulations in this part will supersede the provisions of any lease which is determined to meet the requirements of section 6(a) of the act, to the extent that they cover the same subject matter, with the following exceptions: The provisions of a lease with respect to the area covered by the lease, the minerals covered by the lease, the rentals payable under the lease, the royalties payable under the lease (subject to the provisions of sections 6(a)(8) and 6(a)(9) of the act), and the term of the lease (subject to the provisions of section 6(a)(10) of the act and, as to sulphur, subject to the provisions of section 6(b)(2) of the act) shall continue in effect and, in the event of any conflict or inconsistency, shall take precedence over the regulations in this part.

(b) A lease that meets the requirements of section 6(a) of the act shall also be subject to the mineral leasing regulations applicable to the Outer Continental Shelf, as well as the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way in the Outer Continental Shelf, to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the terms of the lease.

NOTE: The record keeping or reporting requirements of this part have been approved by the Bureau of the Budget in accordance with the Federal Reports Act of 1942. [See 43 CFR, Part 3300.]

PART 290 — APPEALS PROCEDURES

AUTHORITY.—R.S. 463, 25 U.S.C. 2; R.S. 465, 25 U.S.C. 9; sec. 32, 41 Stat. 450, 30 U.S.C. 189; sec. 5, 44 Stat. 1058, 30 U.S.C. 285; sec. 10, 61 Stat. 915, 30 U.S.C. 359; sec. 5, 6, 67 Stat. 464, 465, 43 U.S.C. 1334, 1335; sec. 24, 84 Stat. 1573, 30 U.S.C. 1023.

§290.1 Scope.

The rules and procedures set forth herein apply to appeals to the Director, Geological Survey (and the Commissioner of Indian Affairs when Indian lands are involved) from final orders or decisions of officers of the Conservation Division, Geological Survey, issued under authority of the regulations in chapter II of this title, 43 CFR part 23, 43 CFR subtitle B, chapter II, and 25 CFR part 177. This part also provides for the further right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, from adverse decisions of the Director (and the Commissioner of Indian Affairs when Indian lands are involved) rendered under this part.

§290.2 Who may appeal.

Any party to a case adversely affected by a final order or decision of an officer of the Conservation Division of the Geological Survey shall have a right to appeal to the Director, Geological Survey, unless the decision was approved by the Secretary or the Director prior to promulgation.

§290.3 Appeals to Director.

(a) An appeal to the Director, Geological Survey, may be taken by filing a notice of appeal in the office of the official issuing the order or decision within 30 days from service of the order or decision. The notice of appeal shall incorporate or be accompanied by such written showing and argument on the facts and laws as the appellant may deem adequate to justify reversal or modification of the order or decision. Within the same 30-day period, the appellant will be permitted to file in the office of the official issuing the order or decision additional statements of reasons and written arguments or briefs.

(b) The officer with whom the appeal is filed shall transmit the appeal and accompanying papers to the Director, Geological Survey, with a full report and his recommendation on the appeal.

(c) The Director will review the record and render a decision in the case.

§290.4 Oral argument.

Oral argument in any case pending before the Director, Geological Survey, will be allowed on motion in the discretion of such officer and at a time to be fixed by him.

§290.5 Time limitations.

With the exception of the time fixed for filing a notice of appeal, the time for filing any document in connection with an appeal may be extended by the Director, Geological Survey. A request for an extension of time must be filed within the time allowed for filing of the document and must be filed in the same office in which the document in connection with which the extension is requested must be filed.

§290.6 Appeals to the Commissioner of Indian Affairs.

The procedure for appeals under this part shall be followed for permits and leases on Indian land except that with respect to such permits and leases, the Commissioner of Indian Affairs will exercise the functions vested in the Director, Geological Survey.

§290.7 Appeals to the Board of Land Appeals.

Any party to a case adversely affected by a final decision of the Director, Geological Survey, or the Commissioner of Indian Affairs under this part shall have a right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, in accordance with the procedures provided in 43 CFR, "Part 4, Department Hearings and Appeals Procedures." [38 F.R. 10,004, April 23, 1973.]

REGULATIONS PERTAINING TO

MINERAL LEASING

ON THE

OUTER CONTINENTAL SHELF

as contained in

TITLE 43 of the CODE of

FEDERAL REGULATIONS

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Group 3300 — Outer Continental Shelf Leasing

PART 3300 — OUTER CONTINENTAL SHELF LEASING; GENERAL

SUBPART 3300 — OUTER CONTINENTAL SHELF MINERAL DEPOSITS; GENERAL

§3300.0-3 Purpose and authority.

The Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. §1331 et seq.), referred to in this part as "the act," among other things, authorizes the Secretary of the Interior to issue on a competitive basis leases for oil and gas, sulphur, and other minerals in submerged lands of the Outer Continental Shelf, as defined in section 2 of the act. Subject to the supervisory authority of the Secretary, the regulations in this part shall be administered by the Director, Bureau of Land Management, hereinafter referred to in this part as the Director.

§3300.0-4 Applicability of public land laws.

The laws and regulations pertaining to the public lands of the United States are not applicable to the submerged lands of the Outer Continental Shelf. Mineral deposits in the submerged lands of the Outer Continental Shelf are subject to disposition only in accordance with the provisions of the act and the regulations promulgated by the Secretary thereunder.

§3300.1 Persons qualified to hold leases.

Mineral leases issued pursuant to section 8 of the act may be held only by citizens of the United States over 21 years of age, associations of such citizens, States, political subdivisions of a State, or private, public, or municipal corporations organized under the laws of the United States or of any State or Territory thereof.

§3300.3 Helium.

Each lease issued or continued under the act shall be subject to a reservation by the United States of the ownership of and the right to extract helium from all gas produced from the leased area, subject to such rules and regulations as shall be prescribed by the Secretary of the Interior. In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area in the manner required by the United States, for the extraction of helium in such plant or reduction works for that purpose as the United States may provide, whereupon the residue shall be returned to the lessee with no substantial delay in the delivery of gas produced from the well to the purchaser thereof. The lessee shall not suffer a diminution of value of the gas from which the helium has been extracted, or loss otherwise, for which he is not reasonably compensated, save for the value of the helium extracted. The United States shall have the right to erect, maintain, and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium.

§3300.4 Payments of filing charges, bonuses, rentals and royalties.

All payments to the United States required by the act or the regulations in this part shall be made to the oil and gas supervisor of the Geological Survey for the region in which the leased area is situated, except that payments of filing charges, bonuses and first year's rental shall be made to the manager of the appropriate field office, Bureau of Land Management, unless otherwise directed by the Secretary. All payments should be made by check, bank draft, or money order payable to the United States Geological Survey, if the payments are made to the Geological Survey, or to the Bureau of Land Management, if the payments are made to that Bureau.

Subpart 3301 — Leasing Areas

§3301.1 Leasing maps.

(a) Any area of the Outer Continental Shelf which has been appropriately platted as provided in paragraph (b) of this section is subject to lease for any mineral not included in a subsisting lease issued under the act or meeting the requirements of subsection (a) of section 6 of the act, unless before any lease is offered or issued the unit is (1) withdrawn from disposition pursuant to section 12(a) of the act, or (2) designated as an area or part of an area restricted from operation under section 12(d) of the act.

(b) As the need arises, the Bureau of Land Management will prepare official leasing maps of areas of the Outer Continental Shelf, which will be made to conform so far as practicable to the method of tract designation established by the adjoining State. The area included in each mineral lease shall be described in accordance with the official leasing map.

§3301.2 Resources evaluation.

From time to time the Director may announce tentative schedules of lease sales of Outer Continental Shelf areas. At such time as an area is initially considered for mineral leasing, or as the need arises, the Director shall request the Geological Survey to prepare a summary report describing the general geology and potential mineral resources of the area and shall request other interested Federal agencies to prepare reports describing to the extent known any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment.

§3301.3 Nominations of tracts.

In selecting tracts for oil and gas, sulphur, or other mineral leasing, the Director will receive and consider nominations of tracts or requests describing areas and expressing an interest in leasing of minerals, or, from time to time, upon his own motion, upon approval of the Secretary, may issue calls for nominations of tracts for the leasing of minerals in specified areas. Nominations of tracts should be addressed to the Director, with copies to the appropriate Bureau of Land Management field office and the appropriate oil and gas supervisor of the Geological Survey. The Director, Geological Survey, shall submit recommendations to the Director on tract selections and lease terms and conditions.

§3301.4 Selection of tracts.

The Director, prior to the final selection of tracts for leasing, either selected on his own motion or nominated pursuant to §3301.3 of this subpart, shall evaluate fully the potential effect of the leasing program on the total environment, aquatic resources, aesthetics, recreation, and other resources in the entire area during exploration, development and operational phases. To aid him in his evaluation and determinations he shall request and consider the views and recommendations of appropriate Federal agencies, may hold public hearings after appropriate notice, and may consult with State agencies, organizations, industries,

and individuals. The Director shall develop special leasing stipulations and conditions when necessary to protect the environment and all other resources, and such special stipulations and conditions shall be contained in the proposed notice of lease offer. The proposed notice of lease offer, together with all views and recommendations received and the Director's findings or actions thereon, shall be submitted to the Secretary for final approval.

§3301.5 Notice of lease offer.

Upon approval of the Secretary, the Director shall publish the notice of lease offer at the expense of the United States in the *Federal Register*, as the official publication, and in other publications as may be desirable. The publication in the *Federal Register* shall be at least 30 days prior to the date of the sale. The notice shall state the place and time at which bids will be filed, and the place, date, and hour at which bids will be opened. The notice shall contain any special stipulations or conditions which will become a part of any lease issued pursuant to such notice, including stipulations or conditions for the protection of the environment, aquatic life and other resources.

§3301.6 Tracts subject to drainage.

Upon direction of the Secretary, the Director, after obtaining the recommendation of the Director, Geological Survey, is authorized to publish on his own motion notices of lease offer of tracts which have been determined by the Director, Geological Survey, to be subject to drainage of their oil and gas deposits from wells on other tracts. The Director may request and consider the views and recommendations of appropriate Federal and State agencies prior to publishing the notice of lease offer. The notice shall be published in accordance with section 3301.5 of this subpart.

Subpart 3302 — Issuance of Leases

§3302.1 General.

Tracts will be offered for lease by competitive sealed bidding under conditions specified in the notice of lease offer. Each oil and gas lease issued pursuant to section 8 of the act shall cover a compact area not exceeding 5,760 acres.

§3302.2 Term.

(a) All oil and gas leases shall be issued for a term of 5 years and so long thereafter as oil or gas may be produced from the leasehold in paying quantities, or drilling or well reworking operations, as approved by the Secretary under §3305a.1 of this part, are conducted thereon.

(b) All sulphur leases shall be issued for a term of 10 years and so long thereafter as sulphur may be produced from the leasehold in paying quantities or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

(c) Other mineral leases shall be issued for such terms as may be prescribed at the time of offering the leases in the notice of lease offer.

§3302.4 What must accompany bids.

(a) A separate bid must be submitted for each lease unit described in the notice of lease offer. A bid may not be submitted for less than an entire unit. Each bidder must submit with his bid a certified or cashier's check or bank draft on a solvent bank, or a money order or cash, for one-fifth of the amount of the cash bonus. If the bidder is an individual, he must submit with his bid a statement of his citizenship. If the bidder is an association (including a partnership), the bid shall be accompanied also by a certified copy of the articles of association or appropriate reference to the record of the Bureau of Land Management in which such a copy has already been filed, with a statement as to any subsequent amendments. If the bidder is a corporation, the following additional information shall be submitted with the bid.

(1) A certified copy of the articles of incorporation and a copy either of the minutes of the meeting of the board of directors or of the by-laws indicating that the person signing the bid has authority to do so, or, in lieu of such a copy, a certificate by the secretary or the assistant secretary of the corporation to that effect, over the corporate seal or appropriate reference to the record of the Bureau of Land Management in connection with which such articles and authority have been previously furnished.

(b) All bidders are warned against violation of the provisions of Title 18 U.S.C. section 1860, prohibiting unlawful combination or intimidation of bidders.

§3302.5 Award of lease.

Sealed bids received in response to the notice of lease offer shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids will be accepted or rejected at that time. In accordance with section 8 of the act, leases will be awarded only to the highest responsible qualified bidder. The United States reserves the right and discretion to reject any and all bids received for any tract, regardless of the amount offered. Awards of leases will be made only by written notice from the authorized officer. Such notices shall transmit the lease forms for execution. In the event the highest bids are tie bids, tie bidders may file with the Director within 15 days after notification an agreement to accept the lease jointly, otherwise all bids will be rejected. If the authorized officer fails to accept the highest bid for a

lease within 30 days after the date on which the bids are opened, all bids for such lease will be considered rejected. Notice of his action will be transmitted promptly to the several bidders. If the lease is awarded, three copies of the lease will be sent to the successful bidder and he will be required not later than the 15th day after his receipt thereof, or the 30th day after the date of the sale, whichever is later, to execute them, pay the first year's rental, the balance of the bonus bid, and file a bond as required in §3304.1. Deposits on rejected bids will be returned. If the successful bidder fails to execute the lease or otherwise comply with the applicable regulations, his deposit will be forfeited and disposed of as other receipts under the act. If before the lease is executed on behalf of the United States the land is withdrawn or restricted from leasing, all payments made by the bidder will be refunded. If the awarded lease is executed by an agent acting in behalf of the bidder, the lease must be accompanied by evidence that the bidder authorized the agent to execute the lease. When the three copies of the lease are executed by the successful bidder and returned to the authorized officer, the lease will be executed on behalf of the United States, and one fully executed copy will be mailed to the successful bidder.

§3302.6 Form.

Oil and gas leases and leases for sulphur will be issued on forms approved by the Director. Other mineral leases will be issued on such forms as may be prescribed by the Secretary.

§3302.7 Dating of leases.

All leases issued under the regulations in this part will be dated and become effective as of the first day of the month following the date the leases are signed on behalf of the lessor, except that, when prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart 3303 — Rentals and Royalties

§3303.1 Rentals.

An annual rental shall be due and payable in advance on the first day of each lease year prior to discovery at the rate specified in the lease. The owner of any lease created by the assignment of a portion of a producing lease and on which assigned portion there is no discovery shall be required to pay an annual rental for such assigned portion at the rate per acre specified in the lease payable each lease year following the year in which the assignment became effective and prior to a discovery on such segregated portion.

§3303.2 Royalties.

Royalties shall be at the rate specified in the lease but in no event shall the royalty on oil and gas be less than 12 1/2 percent of the amount or value of the production saved, removed or sold from the lease, nor on sulphur less than 5 percent of the gross production of value of the sulphur at the wellhead.

§3303.3 Minimum royalty.

Each lessee shall pay the minimum royalty specified in the lease at the end of each lease year beginning with the first lease year following a discovery on the lease.

§3303.5 Effect of suspensions on royalty and rental.

(a) In the event that under the provisions of 30 CFR 250.12(c) or (d)(1) the regional oil and gas supervisor of the Geological Survey with respect to any lease directs the suspension of both operations and production, or with respect to a lease on which there is no producible well directs the suspension of operations, no payment of rental or minimum royalty will be required for or during the period of the suspension. In the event that under the provisions of 30 CFR 250.12(d)(1) the supervisor approves, at the request of a lessee, the suspension of operations or production, or both, or under the provisions of 30 CFR 250.12(d)(3) suspends any operation including production, the lessee will not be relieved of the obligation to pay rental, minimum royalty or royalty for or during the period of suspension.

(b) In the event the anniversary date of a lease falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a), of this section, the prorated rentals or minimum royalties, if any are due and payable as of the date the suspension period terminates, shall be computed and notice thereof given the lessee. Payment of the amount due shall be made by the lessee within 30 days after receipt of such notice. The anniversary date of a lease will not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

Subpart 3304 — Bonds

§3304.1 Amount of bond required of lessee.

The successful bidder prior to the issuance of an oil and gas or sulphur lease must furnish a corporate surety bond in the sum of $50,000 conditioned on compliance with all of the terms of the lease, unless he already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of oil and gas and sulphur leases held by him on the Outer Continental Shelf in the (a) Gulf of Mexico, (b) along the Pacific Coast, or (c) along the Atlantic Coast, as may be appropriate. An operator's bond in the same amount may be substituted at any time for the lessee's bond. The United States reserves the right to require additional security in the form of a

lessee fails to comply with any provision of the act or lease or applicable regulations in force and effect on the date of the issuance of the lease, if such failure to comply continues for 30 days after mailing of notice by registered letter to the lease owner at his record post office address. Any such cancellation is subject to judicial review as provided in section 8(j) of the act upon the complaint of any person. Producing leases issued under the act may be canceled for such failure only by judicial proceedings in the manner prescribed in section 5(b)(2) of the act. Any lease issued under the act, whether producing or not, will be canceled by the authorized officer upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee.

Subpart 3307 — Mineral Deposits Affected by Section 6 of Outer Continental Shelf Lands Act

§3307.1 Effect of regulations on provisions of lease.

(a) As contemplated by section 6(b) of the act, the preceding regulations in this part so far as they are applicable and the following regulations will supersede the provisions of any lease which is determined to meet the requirements of section 6(a) of the act, to the extent that they cover the same subject matter, with the following exceptions: The provisions of a lease with respect to the area covered by the lease, the minerals covered by the lease, the rentals payable under the lease, the royalties payable under the lease (subject to the provisions of sections 6(a)(8) and 6(a)(9) of the act), and the term of the lease (subject to the provisions of section 6(a)(10) of the act and, as to sulphur, subject to the provisions of section 6(b)(2) of the act) shall continue in effect and, in the event of any conflict or inconsistency, shall take precedence over those regulations.

(b) A lease that meets the requirements of section 6(a) of the act shall also be subject to all operating and conservation regulations applicable to the Outer Continental Shelf, as well as the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way in the Outer Continental Shelf, to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the term of the lease. Nothing herein should be construed to waive compliance with any provision of any State lease the subject matter of which is not covered in the regulations in this part.

§3307.2 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the act will not preclude the issuance of other leases of the same area for deposits of other minerals: *Provided*, That no lease of minerals other than those covered by the lease shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease: *And provided further*, That no sulphur leases will be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the act.

§3307.3 Obligations of lessee.

§3307.3-1 Bonds.

Within 30 days from the effective date of the regulations in this part or within such further period or periods as may be fixed from time to time by the authorized officer, the lessee under a lease meeting the requirements of section 6(a) of the act must furnish a bond as provided in §3304.1.

§3307.3-2 Wells.

(a) After due notice in writing, the lessee shall drill and produce such wells as the Secretary may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practice.

(b) At the election of the lessee, the lessee may drill and produce other wells in conformity with any system of well spacing or production allotments affecting the area, field, or pool in which the leased area or any part thereof is situated, which is authorized or sanctioned by applicable law or by the Secretary.

(c) The lessee shall drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties, or in lieu thereof, with the consent of the Oil and Gas Supervisor, to pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that this lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of this lease.

§3307.3-3 Inspection.

The lessee shall keep open at all reasonable times for the inspection of any duly authorized officer of the Department of the Interior, the leased area and all wells, improvements, machinery and fixtures thereon and all books, accounts, maps and records relative to operations and surveys or investigations on or with regard to the leased area or under the lease.

§3307.3-4 Diligence; compliance with regulations and orders.

The lessee shall exercise reasonable diligence in drilling and producing the wells herein provided for;

supplemental bond or bonds or to increase the coverage of an existing bond if, after operations or production have begun, such additional security is deemed necessary. The amount of bond coverage on leases for other minerals will be determined at the time of the offer to lease and will be stated in the notice of a lease offer. Where upon a default, the surety on an Outer Continental Shelf Mineral Lease Bond makes payment to the Government of any indebtedness under a lease secured thereby, the face amount of such bond and the surety's liability thereunder shall be reduced by the amount of such payment. Thereafter, upon penalty of cancellation of all of the leases covered by such bond, the principal shall post a new bond, on a form approved by the Director, in the amount of $300,000 within 6 months after notice, or within such shorter period as the authorized officer of the Bureau of Land Management may fix. However, in lieu thereof, the principal may within that time file separate bonds for each lease. The provisions hereof may be made applicable to any bond in force at the time of the approval of the amendment of this section by filing in the local office of the Bureau of Land Management, a written consent to that effect and an agreement to be bound by the provisions hereof executed by the principal and surety. Upon receipt thereof the bond will be deemed to be subject to the provisions of this section.

§3304.2 Form of bond.

Bonds furnished by lessee or operator for a single lease will be on forms approved by the Director. The $300,000 bond will be on a form approved by the Director.

Subpart 3305 — Assignment or Transfers

§3305.1 Assignment of leases or interest therein.

Leases, or any undivided interest therein, may be assigned in whole or as to any officially designated subdivision subject to the approval of the authorized officer, to any one qualified under §3380.1 to take and hold a lease. Any assignment made under this section shall, upon approval, be deemed to be effective on and after the first day of the lease month following its filing in the appropriate office of the Bureau of Land Management, unless at the request of the parties an earlier date is specified in the Director's approval. The assignor shall be liable for all obligations under the lease accruing prior to the approval of the assignment.

§3305.2 Requirements for filing of transfers.

(a)(1) All instruments of transfer of a lease or of an interest therein, including operating agreements, subleases, and assignments of record interests, must be filed in triplicate for approval within 90 days from the date of final execution with a statement over the transferee's own signature with respect to citizenship and qualifications similar to that required of a lessee and must contain all of the terms and conditions agreed upon by the parties thereto. Carried working interests, overriding royalty interests, or payments out of production, may be created or transferred without requirement for filing or approval.

(2) An application for approval of any instrument required to be filed must be accompanied by a fee of $10, and an application not accompanied by payment of such a fee will not be accepted for filing. Such fee will not be returned even though the application later be withdrawn or rejected in whole or in part.

(b) Where an attorney in fact, in behalf of the holder of a lease, operating agreement or sublease signs an assignment of the agreement, lease, or interest, or signs the application for approval, there must be furnished evidence of the authority of the attorney in fact to execute the assignment or application and the statement required by §3302.4.

(c) Where an assignment creates a segregated lease a bond must be furnished in the amount prescribed in §3304.1. Where an assignment does not create separate leases the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

(d) In order for the heirs or devisees of a deceased holder of a lease, or any interest therein, to be recognized by the Department as the lawful successor to such lease or interest, evidence of their status as such heirs or devisees must be furnished in the form of a certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or, if no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will, and, in all cases, the statements of the heirs or devisees that they are the persons named as successors to the estate with evidence of their qualifications as provided in §3302.4. In the event such heirs or devisees are unable to qualify to hold the lease or interest they will nevertheless be recognized as the lawful successors of the deceased for a period of not to exceed 2 years from the date of death of their predecessor in interest.

§3305.3 Separate assignments required for transfer of record title to leases.

A separate instrument of assignment must be filed for each lease when transfers involve record titles. When transfers to the same person, association, or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee will be sufficient.

§3305.4 Effect of assignment of particular tract.

(a) When an assignment is made of all of the record title to a portion of the acreage in a lease, the assigned

and retained portions become segregated into separate and distinct leases. The assignee becomes a lessee of the Government as to the segregated tract and is bound by the terms of the lease as though he had obtained the lease from the United States in his own name, and the assignment after its approval will be the basis of a new record. Royalty, minimum royalty, and rental provisions of the original lease shall apply separately to each segregated portion.

(b) In the case of an assignment of a portion of an oil and gas lease the segregated leases shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas may be produced from the original leased area in paying quantities or drilling or well reworking operations as approved by the Secretary are conducted thereon.

Subpart 3305a — Extension of Leases

§3305a.1 Extension of leases by drilling or well reworking operations.

(a) The Secretary shall be deemed to have approved, within the meaning of section 8(b)(2) of the Outer Continental Shelf Lands Act, drilling or well reworking operations, conducted on the leased area in the following instances:

(1) If, any discovery of oil or gas in paying quantities has been made on the leasehold, and within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, the production thereof shall cease at any time, or from time to time, from any cause and production is restored or drilling or well reworking operations are commenced within 90 days thereafter, and such drilling or well reworking operations (whether on the same or different wells) are prosecuted diligently until production is restored in paying quantities.

(2) If, within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, at any time, or from time to time, lessee is engaged in drilling or well reworking operations on the leasehold and there is no well on the leasehold capable of producing in paying quantities and the lessee diligently prosecutes such operations (whether on the same or different wells) with no cessation of more than 90 days.

(b) The Secretary may approve such other operations for drilling or reworking upon application of lessee.

(c) Nothing in this section obviates the necessity of obtaining the Oil and Gas Supervisor's approval of a plan or notice of intention to drill or of complying with the provisions of 30 CFR Part 250.

§3305a.2 Directional drilling.

A lease may be maintained in force by directional wells drilled under the leased area from surface locations on adjacent or adjoining land not covered by the lease. In such circumstances, drilling shall be considered to have commenced on the leased area when drilling is commenced on the adjacent or adjoining land for the purpose of directionally drilling under the leased area through any directional well surfaced on adjacent or adjoining land, and production, drilling, or reworking of any such directional well shall be considered production or drilling or reworking operations (as the case may be) on the leased area for all purposes of the lease.

§3305a.3 Compensatory payments.

In the event that an oil and gas lessee makes compensatory payments as provided in 30 CFR 250.33 and in the event that the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

§3305a.4 Effect of suspensions on lease term.

In the event that under the provisions of 30 CFR 250.12(c) or (d)(1), the regional Oil and Gas Supervisor of the Geological Survey directs the suspension of either operations or production, or both, with respect to any lease, the term of the lease will be extended by a period equivalent to the period of the suspension. In the event that under the provisions of 30 CFR 250.12(c) or (d)(1), the supervisor approves the suspension of either operations or production, or both, with respect to any lease, the term of the lease will not be deemed to expire so long as the suspension remains in effect.

Subpart 3306 — Termination of Leases

§3306.1 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivision thereof may be surrendered by the record title holder by filing a written relinquishment, in triplicate, with the appropriate office of the Bureau of Land Management. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and his surety to make payment of all accrued rentals and royalties and to abandon all wells on the land to be relinquished to the satisfaction of the Oil and Gas Supervisor.

§3306.2 Cancellation of leases.

Any nonproducing lease issued under the act may be canceled by the authorized officer whenever the

shall carry on all operations in accordance with approved methods and practices including those provided in the operating and conservation regulations for the Outer Continental Shelf; shall remove all structures when no longer required for operations under the lease to sufficient depth beneath the surface of the waters to prevent them from being a hazard to navigation and the fishing industry; and shall carry out at expense of the lessee all lawful and reasonable orders of the lessor relative to the matters in this section. On failure of the lessee so to do the lessor shall have the right to enter on the property and to accomplish the purpose of such orders at the lessee's cost: *Provided*, That the lessee shall not be held responsible for delays or casualties occasioned by causes beyond the lessee's control.

§3307.3-5 Freedom of purchase.

The lessee shall accord all workmen and employees directly engaged in any of the operations under the lease complete freedom of purchase.

§3307.3-6 Removal of property on termination of lease.

Upon the expiration of any lease, or the earlier termination thereof as provided in the regulations in this part, the lessee shall within a period of one year thereafter remove from the premises all structures, machinery, equipment, tools, and materials other than improvements needed for producing wells or for drilling or producing other leases, and other property permitted by the lessor to be maintained.

§3307.4 Exploration and operations.

§3307.4-1 Purchase of production.

In time of war, or when the President of the United States shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of the oil or gas produced from the leased area, as provided in section 12(b) of the act.

§3307.4-2 Suspension of operations during war or national emergency.

Upon recommendation of the Secretary of Defense, during a state of war or national emergency declared by the Congress or the President of the United States after August 7, 1953, the Secretary is authorized to suspend any or all operations under a lease, as provided in section 12(c) of the act: *Provided*, That just compensation shall be paid by the United States to the lessee whose operations are thus suspended.

§3307.4-3 Restriction of exploration and operations.

The United States shall have the right, as provided in section 12(d) of the act, to restrict from exploration and operations the leased area or any part thereof which may be designated by and through the Secretary of Defense, with the approval of the President of the United States, as, or as part of, an area of the Outer Continental Shelf needed for national defense. So long as such designation remains in effect no exploration or operations may be conducted on the surface of the leased area or the part thereof included within the designation except with the concurrence of the Secretary of Defense. If operations or production under any lease within any such restricted area shall be suspended, any payments of rentals, minimum royalty, and royalty prescribed by such lease likewise shall be suspended during such period of suspension of operations and production, and the term of such lease shall be extended by adding thereto any such suspension period, and the United States shall be liable to the lessee for such compensation as is required to be paid under the Constitution of the United States.

§3307.4-4 Geological and geophysical exploration; rights-of-way.

The United States reserves the right to authorize the conduct of geological and geophysical exploration in the leased area which does not interfere with or endanger actual operations under the lease and the right to grant such easements or rights-of-way, upon, through, or in the leased area as may be necessary or appropriate to the working of other lands containing the deposits described in the act, and to the treatment and shipment of products thereof by or under authority of the Government, its lessees or permittees, and for other public purposes, subject to the provisions of section 5(c) of the act where they are applicable and to all lawful and reasonable regulations and conditions prescribed by the Secretary thereunder.

§3307.4-5 Leases of sulphur and other mineral.

The United States reserves the right to grant sulphur leases and leases of any mineral other than oil, gas, and sulphur within the leased area or any part thereof, subject to the provisions of sections 8(c), 8(d), and 8(e) of the act and all lawful and reasonable regulations prescribed by the Secretary thereunder: *Provided*, That no such sulphur lease or lease of other mineral shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the lease which is continued under section 6 of the act.

§3307.5 Remedies in case of default.

(a) Whenever the lessee fails to comply with any of the provisions of the act or of the lease or of the lawful and reasonable regulations issued within 90 days after the authorized officer has determined that the lease meets the requirements of section 6(a) of the act, the lease shall be subject to cancellation as follows:

(1) If, at the time of such default, no well is producing, or is capable of producing, oil or gas in paying quantities from the leased area, whether such well be drilled from a surface location within the leased area or be directionally drilled from a surface location on adjacent or adjoining lands the lease may be canceled by the Secretary (subject to the right of judicial review as provided in section 8(j) of the act) if such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address.

(2) If, at the time of such default, any well is producing, or is capable of producing, oil or gas in paying quantities from the leased area, whether such well be drilled from a surface location within the leased area or be directionally drilled from a surface location on adjacent or adjoining lands, the lease may be canceled by an appropriate proceeding in any United States district court having jurisdiction under the provisions of section 4(b) of the act if such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address.

(b) If any such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address, the lessor may then exercise any legal or equitable remedy which the lessor may have; however, the remedy of cancellation of the lease may be exercised only under the conditions and subject to the limitations set out in paragraph (a) of this section, or pursuant to section 8(i) of the act.

(c) A waiver of any particular default shall not prevent the cancellation of the lease or the exercise of any other remedy the lessor may have by reason of any other cause or for the same cause occurring at any other time.

§3307.6 Heirs and successors in interest.

Each obligation under any lease and under the regulations in this part shall extend to and be binding upon, and every benefit thereunder shall inure to, the heirs, executors, administrators, successors, or assigns of the lessee.

ATTACHMENT B

Notice to Lessees and Operators Of Federal

Oil, Gas, And Sulphur Leases

In The Outer Continental Shelf

Gulf Of Mexico Area

OCS Order Nos. 1 through 12—Gulf of Mexico

UNITED STATES
DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY
CONSERVATION DIVISION

Branch Of Oil and Gas Operations
Gulf Of Mexico Area

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UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 provides as follows:

> Well designations. The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Identification of Platforms, Fixed Structures. Platforms and structures, other than individual wellhead structures and small structures, shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: The name of lease operator, the name of the area, the block number of the area in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example:

   "The Blank Oil Company operates 'C' platform in Block 37 of South Timbalier Area."

   The identifying sign on the platform would show:

   "BOC - S.T. - 37 - C."

2. Identification of Single Well Structures and Small Structures. Single well and small structures may be identified with one sign only, with letters and figures not less than 3 inches in

height. The information shall be abbreviated as in the following example:

> *"The Blank Oil Company operates well No. 1 which is equipped with a protective structure, in Block 68 in the East Cameron Area."*

The identifying sign on the protective structure would show:

> *"BOC - E.C. - 68 - No. 1"*

3. *Identification of Wells. The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41 and 250.91. All exploratory wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order. Initial development wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order which shall continue in effect until field rules are issued. After field rules have been established by the supervisor, development wells shall be drilled in accordance with such rules; except that in fields containing more than five development wells, additional development wells commenced prior to October 1, 1969, may be excluded from provisions of this Order, as approved by the supervisor, to permit time for the establishment of field rules.

Where sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application to the supervisor for the establishment of field rules, but the operator(s) shall make such application before more than five development wells have been drilled in the field. Operators may also make application for the establishment of field rules for existing fields containing more than five development wells on the date of this Order. Each Application to Drill (Form 9-331C) for exploratory wells and development wells not covered by field rules shall include all information required under 30 CFR 250.91 and the integrated casing, cementing, mud, and blowout prevention program for the well, and shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, and production casing. All depths refer to true vertical depth (TVD).

A. *<u>Drive or Structural Casing</u>. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.*

B. *<u>Conductor and Surface Casing - General Principles</u>. Determination of proper casing setting depths shall be based upon all geologic factors including the presence or absence of hydrocarbons and water depths on a well-for-well basis. The setting depths of all casing strings shall be determined by taking into account formation fracture gradients and hydrostatic pressure to be contained within the well bore. The conductor and surface casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition.*

(1) *<u>Conductor Casing</u>. This casing shall be set in accordance with the table below. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.*

(2) *<u>Surface Casing</u>. This casing shall be set at a depth in accordance with the table below and cemented in a manner necessary to protect all fresh water sands and provide well control until the next string of casing is set. This casing shall be cemented with a quantity sufficient to fill the calculated annular space to (a) at least 1,500 feet above the casing shoe, or (b) within 200 feet below the conductor casing. Whenever there are any indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either recement or squeeze cement the shoe after drilling out.*

(3) *<u>Conductor and Surface Casing Setting Depths</u>. These strings of casing shall be set at the depths specified in the following table subject to minor variation to permit the*

casing to be set in a competent bed; provided, however, that the conductor casing shall be set before drilling into shallow formations known to contain oil or gas or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure conditions, the district engineer may prescribe the exact setting depth within the ranges specified below.

Required Setting Depth Below Gulf Floor (TVD in feet)

Proposed Total Depth of Well or Depth of First Full String of Intermediate Casing (TVD in feet from Rorary Table)	*Surface Casing*		*Conductor Casing*	
	Minimum	*Maximum*	*Minimum*	*Maximum*
0 - 7,000	1,500	2,500	300	800
7,000 - 9,000	1,750	3,000	400	800
9,000 -11,000	2,250	3,500	500	900
11,000 -13,000	3,000	4,000	600	900
13,000 -Below	3,500	4,500	700	1,000

C. *Intermediate Casing. This string of casing shall be set when required by anticipated abnormal pressure, mud weights, sediment and other well conditions. The intermediate casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.*

D. ***Production Casing. This string of casing shall be set before completing the well for production. The production casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost producible hydrocarbon zone must be used. When a liner is used as production casing, the testing of the seal between the liner top and next larger string shall be conducted as in the case of intermediate liners.***

E. *Pressure Testing*. Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the working pressure of the casing. The surface casing shall be tested with water in the top 100 feet of the casing. If the pressure declines more than 10% in 30 minutes, or if there is other indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing shall be tested again in the same manner.

Casing String	Minimum Pressure Test (psi)
Conductor	200
Surface	1,000
Intermediate	1,500 or 0.2 psi/ft., whichever is greater
Liner	1,500 or 0.2 psi/ft., whichever is greater
Production	1,500 or 0.2 psi/ft., whichever is greater

After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for conductor casing string. 12 hours under pressure for all other strings. (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used.)

All casing pressure tests shall be recorded on the driller's log.

2. *Blowout Prevention Equipment*. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

A. *Conductor Casing*. Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and

other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. *Surface Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.*

C. *Intermediate Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) four remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.*

D. *Testing. Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.*

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all

equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

E. Other Equipment. An inside blowout preventer assembly (back pressure valve) and drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel, and an essentially full opening Kelly cock shall be installed at the bottom of the Kelly of such design that it can be run through the blowout preventers.

3. Mud Program - General. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control. Before starting out of hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety device(s) required in subparagraph 2(E) above shall be installed on the drill pipe, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reverse circulated prior to pulling drill stem test tools from the hole.

B. Mud Testing Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) *Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.*

(2) *Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.*

(3) *Mud return indicator to determine that returns essentially equal the pump discharge rate.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Permanent Abandonment.

A. Isolation in Uncased Hole. In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata.

B. Isolation of Open Hole. Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 50 feet, nor more than 100 feet, above the casing shoe with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

(3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. *Plugging or Isolating Perforated Intervals*. A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.

D. *Plugging of Casing Stubs*. If casing is cut and recovered, a cement plug 200 feet in length shall be placed to extend 100 feet above and 100 feet below the stub. A retainer may be used in setting the required plug.

E. *Plugging of Annular Space*. No annular space that extends to the Gulf floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. *Surface Plug Requirement*. A cement plug of a least 150 feet, with the top of the plug 150 feet or less below the Gulf floor, shall be placed in the smallest string of casing which extends to the surface.

G. *Testing of Plugs*. The setting and location of the first plug below the top 150-foot plug, will be verified by either (1) placing a minimum pipe weight of 15,000 pounds on the plug, or (2) testing with a minimum pump pressure of 1,000 psig with no more than a 10 percent pressure drop during a 15-minute period.

H. *Mud*. Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. *Clearance of Location*. All casing and piling shall be severed and removed to at least 15 feet below the Gulf floor and the location shall be dragged to clear the well site of any obstructions.

2. *Temporary Abandonment*. *Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements F and I of paragraph 1 above. When casing extends above the Gulf floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 and 200 feet below the Gulf floor.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

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Chief, Conservation Division

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of operations or production, or both, has been approved. An application for suspension of production for an initial period should be submitted prior to the expiration of the term of a lease. The supervisor may approve a suspension of production provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements of either 1 or 2 below have been met.

1. Production Tests.

   A. Oil Wells. A production test of at least two hours duration, following stabilization, is required.

   B. Gas Wells. A deliverability test of at least two hours duration, following stabilization, or a four-point back-pressure test, is required.

   C. Witnessing and Results. All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

2. *Production Capability.* Information for determining producibility should be submitted in time to permit one week for evaluation and determination. In cases of urgency, determinations may be conveyed orally. The following may be considered as acceptable evidence that a well is capable of producing in paying quantities:

A. An induction-electric log of the well, clearly showing a minimum of 15 feet of producible sand in one section which does not include any interval which appears to be water saturated. All of the section counted as producible must exhibit the following properties:

(1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20 negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water bearing sand may be substituted.

(2) A minimum true resistivity ratio of the producible section to the nearest clean water sand of at least 5:1, provided the producible section exhibits a minimum resistivity of 2.0 ohm-meters.

(3) A porosity log indicating porosity in the producible section.

B. Sidewall cores and core analysis which indicates that the section is producible.

C. A wire line formation test or evidence that an attempt was made to obtain such test. The test results must indicate that the section is producible.

D. All logs run must support other evidence that the section is producible.

Robert F. Evans

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Approved: August 28, 1969

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

(b) Completed Wells. In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the appropriate District office. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. Installation. All new and existing tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-controlled or a surface- or other remotely controlled subsurface safety device, to be installed at a depth of 100 feet or more below the sea floor unless, after application and justification, the well is determined to be incapable of flowing oil or gas. These installations shall be made as required in subparagraphs A and B below within two (2) days after stabilized production is established, and during this period of time the well shall not be left unattended while open to production.

A. *New Wells*. All tubing installations in wells completed after December 1, 1972, shall be equipped with a surface- or other remotely controlled subsurface safety device; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

B. *Existing Wells*. All tubing installations in wells existing on the date of this Order shall be equipped with a surface- or other remotely controlled subsurface safety device when the tubing is first removed and reinstalled after December 1, 1972; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

Tubing installations in existing wells completed from single-well and multi-well satellite caissons or jackets and sea-floor completions may be equipped with a subsurface-controlled subsurface safety device, in lieu of a surface- or other remotely controlled subsurface safety device, upon application, justification, and approval.

C. *Shut-in Wells*. A tubing plug shall be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six (6) months. Such plugs shall be set at a depth of 100 feet or more below the sea floor. All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two (2) days after completion.

D. *Injection Wells*. Subsurface safety devices as required in subparagraphs A and B above shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing oil or gas, which condition shall be verified annually.

2. *Technological Advancement*. As technological research, progress, and product improvement result in increased effectiveness of existing safety devices or the development of new devices or systems, such devices or systems may be required or used upon application, justification, and approval. Applications for routine use shall include evidence that the device or system has been field-tested at least once each month for a minimum of six (6) consecutive months, and that each test indicated proper operation.

3. *Testing and Inspection*. Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

   A. *Surface-Controlled Subsurface Safety Devices*. Each surface- or other remotely controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed and thereafter at intervals not exceeding six (6) months. If the device does not operate properly, it shall be removed, repaired, and reinstalled or replaced and tested to insure proper operation.

   B. *Subsurface-Controlled Subsurface Safety Devices*. Each subsurface-controlled subsurface safety device installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding six (6) months; provided, that such removable devices set in a landing nipple shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding twelve (12) months. Each velocity-type device shall be designed to close at a flow rate not to exceed the larger of either 150 percent of, or 200 BFPD above, the most recent well-test rate which equals or exceeds the approved production rate. The above closing flow rate shall not exceed the calculated capacity of the well to produce against a flowing wellhead pressure of 50 psig. Each preset tubing-pressure-actuated device shall be designed to close prior to reduction of the flowing wellhead pressure to 50 psig.

   C. *Tubing Plugs*. A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding six (6) months. If sustained liquid flow exceeds 400 cc/min., or gas flow exceeds 15 cu. ft./min., the plug shall be removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

4. *Temporary Removal*. Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authority or notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9-331) for a period not to exceed fifteen (15) days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production. The provisions of this paragraph are not applicable to the testing and inspection procedures in paragraph 3 above.

5. *Additional Protective Equipment*. All tubing installations made after the date of this Order in which a wireline- or pumpdown-retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system, or of an independent remote shut-in system.

6. *Departures*. All departures (or waivers) approved prior to the date of this Order are hereby terminated as of December 1, 1972, unless new applications are submitted prior to that date. All such new applications will be considered for approval pursuant to 30 CFR 250.12(b) and the requirements of this Order. All applications for departures shall include a detailed statement of the well conditions, efforts made to overcome any difficulties, and proposed alternate safety measures.

7. *Emergency Action*. All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this Order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such as an impending hurricane, such device or plug shall be promptly installed within the limits of practicability, due consideration being given to personnel safety.

8. *Records*. The operator shall maintain the following records for a minimum period of one year for each subsurface safety device and tubing plug installed, which records shall be available to any authorized representative of the Geological Survey.

   A. *Field Records*. Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:

(1) *A record which will give design and other information; i.e., make, model, type, spacers, bean and spring size, pressure, etc.*

(2) *Verification of assembly by a qualified person in charge of installing the device and installation date.*

(3) *Verification of setting depth and all operational tests as required in this Order.*

(4) *Removal date, reason for removal, and reinstallation date.*

(5) *A record of all modifications of design in the field.*

(6) *All mechanical failures or malfunctions, including sand-cutting, of such devices, with notation as to cause or probable cause.*

(7) *Verification that a failure report was submitted.*

B. *Other Records. The following records, as a minimum, shall be maintained at the operator's office:*

(1) *Verified design information of subsurface-controlled subsurface safety devices for the individual well.*

(2) *Verification of assembly and installation according to design information.*

(3) *All failure reports.*

(4) *All laboratory analysis reports of failed or damaged parts.*

(5) *Quarterly failure-analysis report.*

9. *Reports. Well completion reports (Form 9-330) and any subsequent reports of workover (Form 9-331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed in the well or indicate that a departure has been granted.*

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the office of the Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The reporting period shall begin the first day of the month following the date of this

Order. The reports shall be submitted by February 28, May 31, August 31, and November 30 for the periods ending January 31, April 30, July 31, and October 31 of each year.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: June 5, 1972

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Wellhead Equipment and Testing Procedures.*

   A. *Wellhead Equipment. All completed wells shall be equipped with casingheads, wellhead fittings, valves and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to the rated test pressure of the fitting to be installed.*

   B. *Testing Procedure. Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied. Should the pressure at the casinghead reflect the applied pressure, the casing shall be condemned. After corrective measures have been taken, the casing shall be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.*

2. *Storm Choke. All completed wells shall meet the requirements prescribed in OCS Order No. 5.*

3. *Procedures for Multiple or Tubingless Completions.*

A. *Multiple Completions.*

(1) *Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.*

(2) *When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.*

B. *Tubingless Completions.*

(1) *All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.*

(2) *The tubing string(s) shall be new pipe and cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.*

(3) *A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.*

(4) *Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

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UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 7
Effective August 28, 1969

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. Section 250.43 provides as follows:

(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and non-liquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with subsection (b) above, shall be governed by applicable law.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Pollution Prevention. In the conduct of all oil, gas and sulphur operations, the operator shall prevent pollution of the waters of the Gulf of Mexico. The operator shall comply with the following pollution prevention requirements:

   A. Liquid Disposal.

      (1) Oil in any form shall not be disposed of into the waters of the Gulf.

      (2) Liquid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life or property, shall be treated to avoid disposal of harmful substances into the waters of the Gulf.

      (3) Drilling mud containing oil shall not be disposed of into the Gulf. Drilling mud containing toxic substances shall be neutralized prior to disposal.

   B. Solid Waste Disposal.

      (1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the Gulf unless the oil has been removed.

      (2) Mud containers and other solid waste materials shall be incincerated or transported to shore for disposal.

   C. Production Facilities.

      (1) All production facilities, such as separators, tanks, treaters, and other equipment, shall be such as are necessary to control the maximum anticipated pressures and production of oil, gas, and sulphur, and shall be maintained at all times in a manner necessary to prevent pollution.

(2) *All platforms and structures shall be curbed and connected by drains to a collecting tank or sump unless drip pans, or equivalents, are placed under equipment, from which a pollutant may spill into the Gulf, and piped to a tank or sump.*

(3) *The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Non-operator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.*

2. *Inspections and Reports. The operator shall comply with the following pollution inspection and reporting requirements:*

A. *Pollution Inspections.*

(1) *Manned facilities shall be inspected daily.*

(2) *Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at frequent intervals. The district engineer may prescribe the frequency of inspections for these facilities.*

B. *Pollution Reports.*

(1) *All spills or leakage of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the supervisor. All spills or leakage of less than 15 barrels shall be reported to the district engineer when requested by him.*

(2) ***All spills or leakage of oil and liquid pollutants of 15 to 50 barrels shall be reported orally to the district engineer without delay and shall be confirmed in writing.***

(3) ***All spills or leakage of oil and liquid pollutants of a substantial size or quantity, which is defined as more than 50 barrels, and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the supervisor, the district engineer, the Coast Guard, and the Regional Director, Federal Water Pollution Control Administration. All oral reports shall be confirmed in writing.***

(4) Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.

3. Control and Removal.

A. Corrective Action. Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for initiating corrective action to control and remove pollution and such plan shall be filed with the supervisor. Corrective action taken under the plan shall be subject to modification when directed by the supervisor.

B. Equipment. Standby pollution control equipment shall be maintained by or shall be immediately available to each operator at a land base location. This equipment shall include containment booms, skimming apparatus, and approved chemical dispersants and shall be available prior to the commencement of operations. The equipment shall be regularly inspected and maintained in good condition for use. The equipment and the location of land bases shall be approved by the supervisor. The operator shall notify the supervisor of the location at which such equipment is located for operations conducted on or for each lease. All changes in location and equipment maintained at each location shall be approved by the supervisor.

Robert F. Evans
Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

APPROVAL PROCEDURE FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

(a) The Supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under Paragraphs (a) and (b) of Section 250.18 or authorized under any lease issued or maintained under the Act.

The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms, fixed and mobile structures, and artificial islands, including all facilities installed on a platform or structure whether or not operated or owned by the operator. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. The following requirements are applicable to all platforms approved and installed subsequent to the effective date of this Order, and to all platforms when structural and equipment modifications are to be made:

   A. General Design. The design of platforms, fixed structures, and artificial islands shall include consideration of such factors as water depth, surface and subsurface soil conditions, wave and current forces, wind forces, total equipment weight, and other pertinent geological, geographical, environmental, and operational conditions.

B. *Application*. The operator shall submit, in duplicate, the following to the appropriate District Office for approval:

(1) *Design Features*. Information relative to design features on an 8" x 10½" plat or plats showing the platform dimensions, plan and two elevations, number and location of well slots, and water depth. In addition, the plat shall include:

(a) Nominal size and thickness range of piling.

(b) Nominal size and thickness range of jacket column leg.

(c) Nominal size and thickness range of deck column leg.

(d) Design piling penetration.

(e) Maximum bearing and lateral load per pile in tons.

(f) Identification data which shall be the lease number, block number, area, and operator.

(g) The following certification signed and dated with the title of the company representative:

"__Operator__ certifies that this platform has been certified by a registered professional engineer and that the structure will be constructed, operated, and maintained as described in the application, and any approved modification thereto. Certified plans are on file at ______________________."

(2) *Non-design Features*. Information relative to non-design features including the following:

(a) Primary use intended, including drilling, production of oil and gas, sulphur, or salt.

(b) Personnel and personnel transfer facilities including living quarters, boat landings, and heliport.

(c) Type of deck, such as steel or wood, and whether coated with protective material.

(d) Method of protection from corrosion.

(e) Production facilities including separators, treaters, storage tanks, compressors, line pumps, and metering devices, except that when initially designed and utilized for drilling, this information may be submitted prior to installation.

(f) Safety and pollution control equipment and features.

(g) Other information when required.

C. Certified Plan. Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

2. Safety and Pollution Control Equipment and Procedures.

A. The following requirements shall apply to all platforms. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1)(a) through (f), (2), and (3) within three months, with subparagraphs (1)(g) and (4) within six months, and with subparagraphs (5), (6), (7), (8), and (9) within one year, from the effective date of this Order.

(1) The following shut-in devices shall be installed and maintained in an operating condition on all pressurized vessels and water separation facilities when such vessels and separation facilities are in service. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(a) All separators shall be equipped with high-low pressure shut-in sensors, low level shut-in controls, and a relief valve. High liquid level control devices shall be installed when the vessel can discharge to a flare.

(b) All pressure surge tanks shall be equipped with a high and low pressure shut-in sensor, a high level shut-in control, flare line, and relief valve.

(c) Atmospheric surge tanks shall be equipped with a high level shut-in sensor.

(d) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors, high-low level shut-in controls, and relief valves, unless determined to be otherwise protected.

(e) Pilot-operated pressure relief valves shall be equipped to permit testing with an external pressure source. Spring-loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high pressure shut-in sensor shall be set no higher than 5% below the rated or designed working pressure and the low pressure shut-in sensor shall be set no lower than 10% below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions involved; except that sensor settings shall not be within 5 psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(f) All sensors shall be equipped to permit testing with an external pressure source.

(g) All flare lines shall be equipped with a scrubber or similar separation equipment.

(2) The following remote and local automatic shut-in devices shall be installed and maintained in an operating condition at all times when the affected well (or wells) is producing. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each such device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(a) All wellhead assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.

(b) All flowlines from wellheads shall be equipped with high-low pressure sensors located close to the wellhead. The pressure sensors shall be set to activate the wellhead valve in the event of abnormal pressures in the flowline.

(c) All headers shall be equipped with check valves on the individual flowlines. The flowline and valves from each well located upstream of, and including, the header valves shall withstand the shut-in pressure of that well, unless protected by a relief valve with connections to bypass the header. If there is an inlet valve to a separator, the valve, flowline, and all equipment upstream of the valve shall also withstand shut-in wellhead pressure, unless protected by a relief valve with connections to bypass the header.

(d) All pneumatic shut-in control lines shall be equipped with fusible material at strategic points.

(e) Remote shut-in controls shall be located on the helicopter deck and all exit stairway landings, including at least one on each boat landing. These controls shall be quick-opening valves.

(f) All pressure sensors shall be tested for proper pressure settings monthly for at least four months. At such time as the monthly results are consistent, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(g) All automatic wellhead safety valves shall be tested for operation weekly. All automatic wellhead safety valves shall be tested for holding pressure monthly. If these results are consistent, a longer period of time between pressure tests, not to exceed quarterly, may then be approved by the Supervisor. In the event that any pressure testing sequence, exceeding monthly, reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(h) Check valves shall be tested for holding pressure monthly for at least four months. At such time as the monthly results are satisfactory, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(i) A complete testing and inspection of the safety system shall be witnessed by Geological Survey representatives at the time production is commenced. Thereafter, the operator shall arrange for a test every six months. The test shall be conducted when it can be witnessed by Geological Survey representatives.

(j) A standard procedure for testing of safety equipment shall be prepared and posted in a prominent place on the platform.

(3) Curbs, gutters, and drains shall be constructed in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into the Gulf waters. Alternate methods to obtain the same results will be acceptable. These systems shall not permit spilled oil to flow into the wellhead area.

(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails.

(5) The following requirements shall apply to the handling and disposal of all produced waste water discharged into the Gulf of Mexico. The disposal of waste water other than into the Gulf waters shall have the method and location approved by the Supervisor.

(a) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.

(b) Waste water disposal systems shall be designed and maintained to reduce the oil content of the disposed water to an average of not more than fifty ppm. An effluent sampling station shall be located at a point prior to discharge into the receiving waters where a representative sample of the treated effluent can be obtained. On one day each month four effluent samples shall be taken within a 24-hour period and determinations shall be made on the temperature, suspended solids, settleable solids, pH, total oil content, and volume of sample obtained.

All samples shall be taken and all analyses for oil content shall be performed in accordance with the American Society for Testing and Materials test D1340, "Oily Matter in Industrial Waste Water". The Supervisor may approve different methods for determination of oil content if the method to be used is indicated to be reliable. No effluent containing in excess of one hundred ppm of total oil content shall be discharged into the Gulf of Mexico. A written report of the results shall be furnished to the Regional Office annually. The report shall contain dates, time and location of sample, volumes of waste discharge on the date of sampling in barrels per day, and the results of the specific analysis and physical observations.

(6) A firefighting system shall be installed and maintained in an operating condition in accordance with the following:

(a) A fixed automatic water spray system shall be installed in all inadequately ventilated wellhead areas as these areas are defined in Paragraph 9 API RP 500A. These systems shall be installed in accordance with the most current edition of National Fire Protection Association's Pamphlet No. 15.

(b) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A firefighting system using chemicals may be considered for installation in certain platform areas in lieu of a firewater system in that area, if determined to provide equivalent fire protection control.

(c) Pumps for the firewater systems shall be inspected and test-operated weekly. A record of the tests shall be maintained in the field and submitted semi-annually to the appropriate District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alternate firefighting system is provided.

(d) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(e) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the platform and a copy submitted to the appropriate District Office.

(7) An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance with the following:

(a) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are classified as hazardous areas as defined in API RP 500 and the most current edition of the National Electric Code.

(b) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located.

(c) The central control shall be capable of giving an alarm at some point below the lower explosive limit of 1.3% as shown in the Bureau of Mines Bulletin No. 503. This low level shall be for alarm purposes only.

(d) A high level setting of not more than 4.9% shall be used for shut-in sequences and the operation of emergency equipment.

(e) An application for the installation and maintenance of any gas detection system shall be filed with the appropriate District Office for approval. The application shall include the following:

(i) Type, location, and number of detection or sampling heads.

(ii) Cycling, noncycling, and frequency information.

(iii) Type and kind of alarm including emergency equipment to be activated.

(iv) Method used for detection of combustible gas.

(v) Method and frequency of calibration.

(vi) A diagram of the gas detection system.

(vii) Other pertinent information.

(f) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the platform.

(8) The following requirements shall be applicable to all electrical equipment and systems installed:

(a) All engines shall be equipped with low-tension ignition systems containing rigid connections and shielded wiring which shall prevent the release of sufficient electrical energy under normal or abnormal conditions to cause ignition of a combustible mixture.

(b) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the most current edition of the National Electric Code and API RP 500A and B, as appropriate.

(c) Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.

(9) Sewage disposal systems shall be installed and used in all cases where sewage is discharged into the Gulf of Mexico. Sewage is defined as human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes. Following sewage treatment, the effluent shall contain 50 ppm or less of biochemical oxygen demand (BOD), 150 ppm or less of suspended solids, and shall have a minimum chlorine residual of 1.0 mg/liter after a minimum retention time of fifteen minutes.

B. *The requirements of subparagraphs 2.A(3), (4), (8), and (9) shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Gulf of Mexico.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: October 30, 1970

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

APPROVAL PROCEDURE FOR OIL AND GAS PIPELINES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) provides as follows:

(b) The Supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under Paragraph (c) of Section 250.18 or authorized under any lease issued or maintained under the Act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. General Design. All pipelines shall be designed and maintained in accordance with the following:

A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform including pipelines which are not operated or owned by the operator. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) and (2) within six months of the effective date of this Order. The operator shall submit records semi-annually showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(1) All oil and gas pipelines leaving a platform receiving production from the platform shall be equipped with a high-low pressure sensor to directly or indirectly shut-in the wells on the platform.

(2) (a) All oil and gas pipelines delivering production to production facilities on a platform shall be equipped with an automatic shut-in valve connected to the platform's automatic and remote shut-in system.

(b) All oil and gas pipelines coming onto a platform shall be equipped with a check valve to avoid backflow.

(c) Any oil or gas pipelines crossing a platform which do not deliver production to the platform, but which may or may not receive production from the platform, shall be equipped with high-low pressure sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at the platform. This automatic shut-in valve shall be connected to either the platform automatic and remote shut-in system or to an independent remote shut-in system.

(d) All pipeline pumps shall be equipped with high-low pressure shut-in devices.

B. All pipelines shall be protected from loss of metal by corrosion that would endanger the strength and safety of the lines either by providing extra metal for corrosion allowance, or by some means of preventing loss of metal such as protective coatings or cathodic protection.

C. All pipelines shall be installed and maintained to be compatible with trawling operations and other uses.

D. All pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.

E. All pipelines shall be maintained in good operating condition at all times and inspected monthly for indication of leakage using aircraft, floating equipment, or other methods. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the pipeline operator and submitted annually by April 1. The pipeline operator shall submit records indicating the cause, effect, and remedial action taken regarding all pipeline leaks within one week following each such occurrence.

F. All pipelines shall be designed to be protected against water currents, storm scouring, soft bottoms, and other environmental factors.

2. Application. The operator shall submit in duplicate the following to the Supervisor for approval:

A. Drawing on 8" x 10½" plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7) burial depth, if buried.

B. A schematic drawing showing the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, and (3) check valves.

C. General information concerning the pipeline including the following:

(1) Product or products to be transported by the pipeline.

(2) Size, weight, and grade of the pipe.

(3) Length of line.

(4) Maximum water depth.

(5) Type or types of corrosion protection.

(6) Description of protective coating.

(7) Bulk specific gravity of line (with the line empty).

(8) Anticipated gravity or density of the product or products.

(9) Design working pressure and capacity.

(10) Maximum working pressure and capacity.

(11) Hydrostatic pressure and hold time to which the line will be tested after installation.

(12) Size and location of pumps and prime movers.

(13) Any other pertinent information as the Supervisor may prescribe.

3. Completion Report. The operator shall notify the Supervisor when installation of the pipeline is completed and submit a drawing on 8" x 10½" plats showing the location of the line as installed, accompanied by all hydrostatic test data including procedure, test pressure, hold time, and results.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: October 30, 1970 ✓

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL SULPHUR LEASES
IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

SULPHUR DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All exploratory core holes for sulphur and all sulphur development wells shall be drilled in accordance with the provisions of this Order, except that development wells shall be drilled in accordance with field rules when established by the supervisor. Each Application to Drill (Form 9-331C) shall include all information required under 30 CFR 250.91 and the integrated casing, cementing, mud, and blowout prevention program for the well. The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). Special consideration to casing design shall be given to compensate for effects caused by subsidence, corrosion, and temperature variation. All depths refer to true vertical depth (TVD).

   A. Drive or Structural Casing. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor, or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

   B. Conductor Casing. This casing shall be set and cemented before drilling into shallow formations known to contain hydrocarbons or, if unknown, upon encountering such formations. Conductor casing shall extend to a depth of not less than 350 feet nor more than 750 feet below the Gulf floor. A quantity of cement sufficient to fill

the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

C. Caprock Casing. This casing shall be set at the top of the caprock and be cemented with a quantity of cement sufficient to fill the annular space back to the Gulf floor. Stage cementing or other cementing method shall be used to insure cement returns to the Gulf floor.

2. Blowout Prevention Equipment. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

A. Conductor Casing. Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. Caprock Casing. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

C. Testing. Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

D. Other Equipment. A drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel.

3) Mud Program - General. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times. The following mud control and testing equipment requirements are applicable to operations conducted prior to drilling below the caprock casing.

A. Mud Control. Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched,

and any time there is an indication of swabbing, or influx of formation fluids, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom.

B. Mud Testing and Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

Robert F. Evans
Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

INTERIM OIL AND GAS PRODUCTION RATES

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.16 and supersedes Interim OCS Order No. 11, dated December 11, 1970, and the first and second revisions thereof, dated February 11, 1971, and March 29, 1971, respectively. The provisions of this Interim Order and the maximum production rates heretofore approved under Interim Order No. 11, dated December 11, 1970, will remain in full force and effect until superseded, amended, or terminated. 30 CFR 250.16 provides as follows:

> Well potentials and permissible flow. The supervisor is authorized to specify the time and method for determining the potential capacity of any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established by the Secretary.

In accordance with the notice appearing in the Federal Register, dated December 5, 1970 (35 F.R. 18559), the provisions of this Order are applicable to all oil and gas wells located on the Outer Continental Shelf of the Gulf of Mexico off the State of Texas and the undisputed areas off the State of Louisiana; provided, however, this order shall not apply to any wells on oil and gas leases situated landward of the line, or transected by the line, described in paragraph 3 of the Supplemental Decree entered December 20, 1971, in United States v. Louisiana, S. Ct. No. 9, Original (40 L.W. 3287). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12 (b).

1. *Maximum Production Rates.*

A. *Producible Wells.* Effective May 1, 1972, all producible oil and gas wells and reservoirs may be produced at daily rates not to exceed the Maximum Efficient Rate (MER), subject to the limitations set forth in paragraph 5 below.

B. *New Completions and Recompletions.* New oil and gas well completions and recompletions shall be produced at a rate established by the Supervisor. A testing period not to exceed 30 days will be allowed prior to setting the maximum production rate for the well. At the end of the testing period, the operator shall submit a detailed determination of the MER justifying a proposed maximum rate of production for the Supervisor's approval. The initial production test of all completions and recompletions may be witnessed by a representative of the Supervisor.

2. *Definition of MER.* The MER is defined as that rate for each reservoir and each well which, if exceeded, would lead to avoidable underground waste through loss of ultimate recovery of oil and gas from that reservoir. It is dependent on the recovery mechanism operative for the current producing period, and is based on engineering and geological information.

3. *Determination of MER.* On or before May 1, 1972, each operator shall submit reports, for approval by the Supervisor, showing the operator's estimate of the MER for each oil and gas well and reservoir on those leases in the area removed from dispute in *United States v. Louisiana*, S. Ct. No. 9, Original, by entry of the Supplemental Decree of December 20, 1971, in that litigation (40 L.W. 3287). Reports shall be identified by the name of the field, the OCS lease number, the well number, and the designation and depth of the productive zone. As soon as available and prior to July 1, 1972, each operator shall submit the technical information and methods used to determine the MER applicable to each well and reservoir.

Revisions in the operator's estimate of the MER for oil and gas wells and reservoirs located on leases subject to this Interim Order shall be submitted to the Supervisor for approval.

4. *Reports.* Each operator shall submit the following reports for each lease separately to the Regional Office. Initial reports for those leases in the area removed from dispute, referred to in Paragraph 3 above, shall be for the month of April 1972 for the reports required in A, C, and D, below, and for the quarter ending April 1, 1972, for the report required in B below.

A. *A monthly well potential report on a form identical to the Louisiana Department of Conservation Form DM-1R. This report shall be submitted for each month by the 10th day of each succeeding month.*

B. *A gas well deliverability test report on a form identical to the Louisiana Department of Conservation Form DT-1, shall be submitted by January 1, April 1, July 1, and October 1.*

C. *A monthly producer's crude oil and/or condensate report on a form identical to Louisiana Department of Conservation Form R-1. This report shall be submitted for each month by the 25th day of each succeeding month.*

D. *A monthly producer's natural gas report on a form identical to Louisiana Department of Conservation Form R-5P. This report shall be submitted for each month by the last day of each succeeding month.*

5. *Limitations on Production.*

A. *Production rates shall not result in venting or flaring of gas in violation of the Operating Regulations in 30 CFR 250.30.*

B. *In order to provide safe operating conditions and prevent pollution, oil and gas production rates shall not exceed the operating capacity of production, transportation, and storage facilities, including, but not limited to, separators, dehydrators, compressors, surge tanks, and pipelines. All producing operations shall be in accordance with the provisions of OCS Orders Nos. 5, 7, 8 and 9. Production rates shall be maintained at a level to permit efficient operation of subsurface safety devices.*

Robert F. Evans
Robert F. Evans
Supervisor

Approved: April 5 '77

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PUBLIC INSPECTION OF RECORDS

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2. Section 250.97 of 30 CFR provides as follows:

> Public Inspection of Records. Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area.

Section 2.2 of 43 CFR provides in part as follows:

> Determinations as to Availability of Records. (a) Section 552 of Title 5, U.S. Code, as amended by Public Law 90-23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirement but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of

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[1] Subsection (b) of section 552 provides that:
(b) This section does not apply to matters that are--
***
(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;
***
(9) Geological and geophysical information and data, including maps, concerning wells.

the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office or a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June 1967.

(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard.

The operator shall comply with the requirements of this Order. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Availability of Records Filed on or after December 1, 1970. It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office, Metairie, Louisiana.

A. Form 9-152 - Monthly Report of Operations. All information contained on this form shall be available except the information required in the Remarks column.

B. Form 9-330 - Well Completion or Recompletion Report and Log. (1) Prior to commencement of production all information contained on this form shall be available except Item 1a, Type of Well; Item 4, Location of Well, At top prod. interval reported below; Item 22, if Multiple Compl., How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production all information shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(3) *If production has not commenced after an elapsed time of five years from the date of filing Form 9-330 as required in 30 CFR 250.38(b), all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the five-year period the lessee or operator may submit objections to the release of such information. The supervisor, taking into consideration the objections of the lessee, proximity to unleased lands, and the best interests of the United States, may determine that such information shall not be released.*

C. *Form 9-331 - Sundry Notices and Report on Wells.* (1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. *Form 9-331C - Application for Permit to Drill, Deepen or Plug Back.* All information contained on this form, and location plat attached thereto, shall be available except Item 4, Location of Well, At proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. *Sales of Lease Production.* Information contained on monthly Geological Survey computer printout showing sales of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. *Filing of Reports.* All reports on Forms 9-152, 9-330, 9-331, and 9-331C shall be filed in accordance with the following:

A. All reports submitted on these forms after the effective date of this Order shall be filed in two separate sets. All items on the forms in one set shall be completed in full and such forms, and all attachments thereto, shall not be available for public inspection. The additional set shall be completed in full, except that the items described in 1.(A), (B), (C), and (D) above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This additional set shall be made available for public inspection.

B. Copies of reports on these forms which were filed between December 1, 1970, and the effective date of this Order, shall be resubmitted (in duplicate or triplicate, as provided by

the regulations) within 30 days after the effective date of this Order. These reports may exclude the items described in 1. (A), (B), (C), and (D) above, and shall show the words "Public Information" on the lower right-hand corner and shall be made available for public inspection.

3. Availability of Records Filed Prior to December 1, 1970. Information filed prior to December 1, 1970, on the forms referred to in (1) above, is not in a form which can be readily made available for public inspection. Requests for information on these forms shall be submitted to the supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

Robert F Evans

Robert F. Evans
Supervisor

Approved: August 13, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

Notice to Lessees and Operators of Federal Oil and Gas Leases in the Outer Continental Shelf Pacific Region

OCS ORDERS

UNITED STATES
DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY
CONSERVATION DIVISION

Branch of Oil and Gas Operations
Pacific Region

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 provides as follows:

> *Well designations. The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.*

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Identification of Platforms or Fixed Structures. Platforms and structures shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: the name of lease operator, the OCS lease number and the platform or structure designation. The information shall be abbreviated as in the following example:*

    "The Blank Oil Company operates C platform on lease OCS-P 0000".

    The identifying sign on the platform would show:

    "BOC - OCS-P 0000 - C"

2. *Identification of Non-Fixed Platforms or Structures. Floating semi-submersible platforms, bottom-setting mobile and floating drilling ships shall be identified by one sign with letters and figures not less than 12 inches in height affixed to the derrick to be visible from off the vessel with the following information: the name of the lease operator and the OCS lease number.*

3. *Identification of Individual Wells on Platforms*. The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All exploratory wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order. Initial development wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order, and these provisions shall continue in effect until field rules are issued. After field rules have been established by the Supervisor, development wells in the individual fields shall be drilled in accordance with such rules.

Where sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application to the Supervisor for the establishment of field rules, but such applications shall be made before more than five development wells have been drilled in a field. When required by the Supervisor, operators shall make application for the establishment of field rules for existing fields containing more than five development wells on the date of this Order.

Each Application to Drill (Form 9-331C) for exploratory wells and development wells not covered by field rules shall include all information required under 30 CFR 250.91 and the detailed casing, cementing, mud, and blowout prevention program for the well and shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Well Casing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. All casing strings shall be new pipe or equivalent. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, protective casing, and production casing. These casing strings shall be run and cemented prior to drilling below the specified setting depths, subject to minor variations to permit the casing to be set in a competent bed. All depths refer to true vertical depth (TVD) below the ocean floor, unless otherwise specified. Determination

of proper casing setting depths shall be based upon all geological and engineering factors including the presence or absence of hydrocarbons. Formation fracture gradients and formation pressures shall be taken into account.

A. *Drive or Structural Casing*. This casing shall be set by drilling, driving, or jetting to a depth of approximately 100 feet below the ocean floor to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the ocean. This casing may be omitted, when approved by the Supervisor, if there is geological evidence that hydrocarbons will not be encountered while drilling the hole for the conductor casing and is not needed for hole stability.

B. *Conductor Casing*. This casing shall be set at a minimum depth of 300 feet or a maximum depth of 500 feet below the ocean floor; provided, however, the conductor casing shall be set before drilling into shallow formations known to contain oil or gas or, if unknown, upon encountering such formations.

C. *Surface Casing*. This casing shall be set at a minimum depth of 1,000 feet or a maximum depth of 1,200 feet below the ocean floor, but may be set as deep as 1,500 feet in the event the conductor casing is set at least 450 feet below the ocean floor.

D. *Intermediate Casing*. This casing shall be set if the proposed total depth of the well is greater than 3,500 feet (TVD in feet from rotary table). When surface casing is set at 1,500 feet the intermediate casing may be omitted if the proposed total depth of the well is not greater than 4,500 feet. Otherwise, the intermediate casing shall be set before drilling below the setting depths specified in the following table:

Proposed Total Depth of Well or Proposed Depth of First Full String of Protective Casing (TVD in feet from Rotary Table)	Setting Depths for Intermediate Casing (TVD in Feet Below Ocean Floor)	
	Minimum	Maximum
3,500 - 4,500	1,500	3,500
4,500 - 6,000	1,750	3,500
6,000 - 9,000	2,250	3,500
9,000 - 11,000	2,750	3,500
11,000 - 13,000	3,250	3,500
13,000 - Below	3,450	3,550

E. *Protective Casing. When required by well conditions, this casing shall be set at any time when drilling below the surface casing. If a liner is used as a protective string, the lap shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log and shall be witnessed by a Geological Survey representative.*

F. *Production Casing. This casing shall be set before completing the well for production. When a blank or combination liner is run and cemented as production casing, the testing of the lap between the liner top and next larger string shall be conducted as in the case of protective liners. The surface casing shall never be used as production casing.*

G. *Casing Cementing. The structural (if drilled or jetted), conductor, and surface casings shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor. The intermediate casing shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor or at least 100 feet into the next larger string of pipe. The protective casing shall be cemented so that all hydrocarbon zones and abnormal pressure intervals are isolated. The production casing shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons and abnormal pressure intervals, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon zone, not previously cased, must be used. Whenever there are indications of improper cementing, such as lost circulation, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either (1) recement, (2) squeeze the shoe of the casing with cement, either by drilling out and squeezing or by squeezing through perforations at the interval of competent formation nearest the shoe, or (3) displace with cement in sufficient quantity to fill the annular space. Upon determining that the casing shoe has been*

adequately cemented the operator may commence further drilling operations provided that prior to abandonment of the well the annular space behind the conductor, surface, and intermediate casings shall be cemented back to the ocean floor or 100 feet into the next larger string of pipe.

H. Pressure Testing. Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the rated working pressure of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, corrective measures must be taken until a satisfactory test is obtained.

Casing String	Minimum Pressure Test (psi)
Conductor	200
Surface and Intermediate	1,000
Protective	1,500 or 0.2 psi/ft., whichever is greater
Liner	1,500 or 0.2 psi/ft., whichever is greater
Production	1,500 or 0.2 psi/ft., whichever is greater

After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure are used.)

All casing pressure tests shall be recorded on the driller's log.

2. Blowout Prevention Equipment. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed as follows:

A. *Conductor Casing.* Before drilling below this string, at least one remotely controlled hydril type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a pipe of adequate diameter with control valves shall be installed below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the ocean floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. *Surface Casing.* Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) three remotely controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

C. *Intermediate Casing.* Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) four remotely controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

D. Testing. Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, at the following times:

(1) when installed;

(2) before drilling out after each string of casing is set;

(3) not less than once each week while drilling; and

(4) following repairs that require disconnecting a pressure seal in the assembly. The hydril type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The hydril type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a reserve capacity at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

E. Other Equipment. An inside blowout preventer assembly (back pressure valve) and a full opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe in the drill string. Also, a socket type, sealing coupling capable of being dropped

over exposed drill pipe with a full opening safety valve above it shall be maintained on the rig floor for control situations where flow prevents installation of a safety valve. A top kelly cock shall be installed below the swivel and another at the bottom of the kelly of such design that it can be run through the blowout preventers.

3. Mud Program - General. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control. Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. Proper conditioning requires, at a minimum, circulation to the extent that the annulus volume is displaced. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing or influx of formation fluids, the necessary safety device(s) required in subparagraph 2.E. above shall be installed on the drill pipe, the drill pipe shall be run to bottom and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reverse circulated prior to pulling drill stem test tools from the hole.

B. Mud Testing Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests consistent with good operating practice shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return or full hole indicator to determine when returns have been obtained, or when they occur unintentionally, and additionally to determine that returns essentially equal the pump discharge rate.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Permanent Abandonment.

   A. Isolation in Uncased Hole. In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate fluids in the strata in which they are found and to prevent them from escaping into other strata.

   B. Isolation of Open Hole. Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

      (1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

      (2) A cement retainer with effective back pressure control set not less than 50 feet, nor more than 100 feet, above the casing shoe with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

(3) *A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.*

C. *Plugging or Isolating Perforated Intervals. A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations of each separate interval with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.*

D. *Plugging of Casing Stubs. If casing is cut and recovered, thereby leaving a stub inside the next larger string, a cement plug will be set so as to extend 100 feet above and 100 feet below the stub, or a retainer set 50 feet above the stub with 150 feet of cement set below and 50 feet above. A permanent bridge plug set 50 feet above the stub and capped with 50 feet of cement shall be used if the foregoing methods cannot be used. However, if the stub is below the next larger string, plugging must be accomplished in accordance with subparagraph A and B above.*

E. *Plugging of Annular Space. No annular space that extends to the ocean floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.*

F. *Surface Plug Requirement. A cement plug of at least 150 feet, with the top of the plug 150 feet or less below the ocean floor, shall be placed in the smallest string of casing which extends to the surface.*

G. *Testing of Plugs. The setting and location of the first plug below the 150-foot surface plug shall be verified by placing the weight of the drill string or a minimum pipe weight of 15,000 pounds on the plug, whichever is greater. The top of plugs placed opposite open hole or perforations shall be verified as to location.*

H. *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. *Clearance of Location.* All casing and anchor piling shall be severed and removed to at least 5 feet below the ocean floor and the ocean floor shall be cleared of any obstructions.

2. *Temporary Abandonments.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements of subparagraphs 1.E., F., and I. above. When casing extends above the ocean floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 and 200 feet below the ocean floor.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

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Chief, Conservation Division

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved. Any application for suspension of production for an initial period shall be submitted prior to the expiration of the term of a lease. The Supervisor may approve a suspension of production provided at least one well has been drilled on the lease and he determines it to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements below have been met.

1. Oil Wells. A deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing oil in paying quantities.

2. Gas Wells. A four-point back pressure test or a measured deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing gas or gas and condensate in paying quantities.

3. *Witnessing and Results.* All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

D. W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

> (b) Completed wells. In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shut-down controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. All wells capable of flowing oil or gas shall be equipped with a subsurface safety device installed at a depth of 100 feet or more below the ocean floor. Such device shall be installed in all oil and gas wells, including artificial lift wells, unless proof is provided to the Supervisor that such wells are incapable of any natural flow. For shut-in wells capable of flowing oil or gas, a tubing plug may be installed, in lieu of a subsurface safety device, and such plug shall be installed when required by the Supervisor.

2. Subsurface safety devices shall be adjusted, installed, and maintained to insure reliable operation. Each subsurface safety device and tubing plug installed in a well shall be

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tested at intervals not exceeding 6 months. Where a safety valve is set in a landing nipple and is of the type that is controlled from the surface by a hydraulic line or other means, the valve may be tested from the surface to insure proper functioning. If the valve does not operate properly it shall be removed, repaired, reinstalled or replaced and again checked for proper operation.

When a subsurface safety device is removed from a well for repair or replacement, a standby subsurface safety device or tubing plug shall be available at the well location. In the event of an emergency such device shall be immediately installed within the limits of practicability, consideration being given to time, equipment, and personnel safety.

Subsurface safety devices that are an integral part of the tubing string shall be tested at intervals not exceeding six months and, if the test is unsatisfactory, shall be replaced or a removable subsurface device shall be installed.

All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus sealed below the valve or plug setting depth.

3. In all tubing installations made after the effective date of this Order, the tubing string shall be equipped with a surface-controlled subsurface safety device. In high-flow-rate wells or wells producing sand, areas of turbulence above and below such devices shall be protected by flow couplings or other protective equipment. Wells which are presently equipped with direct-controlled subsurface safety devices shall have surface-controlled subsurface safety devices installed the first time the tubing is pulled after the effective date of this Order, or within one year after the effective date of this Order, whichever occurs sooner. The control system for the surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system.

4. The well completion report on Form 9-330 and any subsequent report of workover on Form 9-331 shall state the type and the depth of the subsurface safety device or tubing plug installed in the well or state that the requirement has been waived.

5. *The operator shall maintain records, available at a structure in the field to any authorized representative of the Geological Survey, showing the present status and past history of each subsurface safety device or tubing plug, including dates and details of inspection, testing, repairing, adjustment and reinstallation or replacement. The operator shall submit a copy of such records semiannually to the District Engineer.*

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D. W. Solanas
Supervisor

Approved: June 1, 1971

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Chief, Conservation Division

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Wellhead Equipment and Testing Procedures.

   A. Wellhead Equipment. All completed wells shall be equipped with casingheads, wellhead fittings, valves, and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to 1.5 times the rated working pressure of the fitting to be installed.

   B. Testing Procedure. Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied to the production casing string. Should the pressure at the casinghead reflect the applied pressure, corrective measures must be taken and the casing shall again be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. *Subsurface Safety Device*. All completed wells shall meet the requirements prescribed in OCS Order No. 5.

3. *Procedures for Multiple or Tubingless Completions*.

A. *Multiple Completions*.

(1) Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

(2) When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.

B. *Tubingless Completions*.

(1) All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.

(2) The tubing string(s) shall be new pipe or equivalent and shall be cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.

(3) A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.

(4) Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

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Supervisor

Approved: June 1, 1971

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. Section 250.43 provides as follows:

(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and non-liquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with paragraph (b) of this section, shall be governed by applicable law.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Pollution Prevention. In the conduct of all oil and gas operations, the operator shall not pollute land or water. The operator shall comply with the following pollution prevention requirements.

   A. Liquid Disposal.

   (1) The disposal of produced waste water and sewage shall be in accordance with the provisions of OCS Order No. 8.

   (2) Oil shall not be disposed of into ocean waters.

   (3) Liquid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life or property, shall be treated to avoid disposal of harmful substances into the ocean waters.

   (4) Drilling mud containing oil or toxic substances shall not be disposed of into the ocean waters.

   B. Solid Waste Disposal.

   (1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the ocean waters.

   (2) Mud containers and other solid waste materials shall be transported to shore for disposal.

   C. Production Facilities.

   (1) All production facilities, such as separators, tanks, treaters, and other equipment, shall be operated and maintained at all times in a manner necessary to prevent pollution.

(2) *The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Non-operator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.*

2. *Inspections and Reports. The operator shall comply with the following pollution inspection and reporting requirements and operators shall comply with such instructions or orders as are issued by the Supervisor for the control or removal of pollutants:*

A. *Pollution Inspections.*

(1) *Manned drilling and production facilities shall be inspected daily to determine if pollution is occurring. Such maintenance or repairs as are necessary to prevent pollution of ocean waters shall be immediately undertaken and performed.*

(2) *Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at intervals as prescribed by the District Engineer and necessary maintenance or repairs immediately made thereto.*

B. *Pollution Reports.*

(1) *All spills or leakage of oil and liquid pollutants shall be reported orally without delay to the District Engineer and the Coast Guard and shall be followed by a written report to the District Engineer showing the cause, size of spill, and action taken.*

(2) *All spills or leakage of oil and liquid pollutants of a substantial size or quantity and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the Supervisor, the District Engineer, the Coast Guard, and the Regional Director, Environmental Protection Agency.*

(3) *Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.*

3. ***Control and Removal.***

A. *Corrective Action.* ***Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for initiating corrective action to control and remove pollution and such plan shall be filed with the Supervisor. Corrective action taken under the plan shall be subject to modification when directed by the Supervisor.***

B. *Equipment.* ***Standby pollution control equipment shall be maintained at each operation or shall be immediately available to each operator at an onshore location. This equipment shall include, but need not be limited to, containment booms, skimming apparatus, and chemical dispersants and shall be available prior to the commencement of operations. This equipment shall be the most effective available resulting from the current state of pollution control and removal research and development efforts. The equipment shall be regularly inspected and maintained in good condition for use. The equipment and the location of land bases shall be approved by the Supervisor. Chemical dispersants shall not be used without prior approval of the Supervisor. The operator shall notify the Supervisor of the location at which such equipment is located for operations conducted on each lease. All changes in location and equipment maintained at each location shall be approved by the Supervisor.***

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

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Chief, Conservation Division

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

APPROVAL PROCEDURE FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraph (a) or (b) of section 250.18 or authorized under any lease issued or maintained under the Act.

Platforms, fixed structures and artificial islands are hereinafter referred to as structures. The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms, fixed and mobile structures, and artificial islands, including all facilities installed on a structure whether or not operated or owned by the operator. The requirements of subparagraphs 2.A.(3), (4), (8), and (9) of this Order shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Pacific Region.

Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. The following requirements are applicable to all structures approved and installed subsequent to the effective date of this Order, and to all structures when structural and equipment modifications are to be made:

   A. <u>General Design.</u> The design of structures shall include consideration of such factors as water depth, surface

and subsurface soil conditions, wave and current forces, wind forces, total equipment weight, seismic forces, and other pertinent geological, geographical, environmental, and operational conditions. At the discretion of the Supervisor, the operator may first obtain preliminary approval of the design of the structure by submitting general specifications which will demonstrate that a satisfactory installation can be designed. The operator may then proceed with detailed design work for final approval which shall comply with the requirements listed below.

B. Application. The operator shall submit in duplicate, for approval, the following to the appropriate District Office.

(1) Design Features. Information relative to design features on a plat or plats showing the structure dimensions, plan and two elevations, number and location of well slots, and water depth. In addition, the plat shall include:

(a) Nominal size and thickness range of piling.

(b) Nominal size and thickness range of jacket column leg.

(c) Nominal size and thickness range of deck column leg.

(d) Design piling penetration.

(e) Maximum bearing and lateral load per pile in tons.

(f) Identification data which shall be the OCS lease number, the structure designation, and the name of the lease operator.

(g) The following certification signed and dated with the title of the company representative:

"______________ certifies that this structure has been certified by a registered professional engineer and that the structure is designed to withstand the specific stresses and conditions outlined in subparagraph 1.A. and as detailed in subparagraph 1.B.(2)(g) of OCS Order No. 8 and will be constructed, operated, and maintained as described in the application, and any approved modification thereto. Certified plans are on file at __________________."

(2) Other Features. Information relative to other features including the following:

(a) Primary use intended, including drilling and/or production of oil and gas.

(b) Personnel and personnel transfer facilities, including living quarters, boat landings, and heliport.

(c) Type of deck, such as steel sheeting or open grating, and whether coated with protective material.

(d) Method of protection from corrosion.

(e) Production facilities including separators, treaters, storage tanks, compressors, line pumps, and metering devices, except that when initially designed and utilized for drilling, this information may be submitted prior to installation.

(f) Safety and pollution control equipment and features.

(g) The design paramters used and the maximum stresses for which designed in terms of the specific forces and conditions outlined in subparagraph 1.A. above.

(h) Other information when required.

C. Certified Plan. Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

2. Safety and Pollution Control Equipment and Procedures.

A. The following requirements shall apply to all structures. Subparagraphs 2.A.(3), (4), (8), and (9) shall also apply to mobile drilling structures. Operators of existing structures, including mobile drilling structures, shall have 90 days from the date of this Order in which to comply with the requirements of subparagraphs 2.A.(1) through (8) and one year in which to comply with subparagraph 2.A.(9).

(1) The following devices shall be installed and maintained in an operating condition on all pressurized vessels and water separation facilities when such vessels and separation facilities are in service. The operator shall maintain records on the structure or facility showing the present status and past history of each such device including

dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.

(a) All separators shall be equipped with high-low pressure shut-in sensors, low level shut-in controls, and a relief valve. High liquid level control devices shall be installed when the vessel can discharge to a gas vent line.

(b) All pressure surge tanks shall be equipped with a high and low pressure shut-in sensor, a high level shut-in control, gas vent line, and relief valve.

(c) Atmospheric surge tanks shall be equipped with a high level shut-in sensor.

(d) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors, high-low level shut-in controls, and relief valves, unless they are determined by the Supervisor to be otherwise protected.

(e) Pilot-operated pressure relief valves shall be equipped to permit testing with an external pressure source. Spring-loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high pressure shut-in sensor shall be set no higher than 5% below the rated or designed working pressure and the low pressure shut-in sensor shall be set no lower than 10% below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions involved; except that sensor settings shall not be within 5 psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(f) *All pressure-operated sensors shall be equipped to permit testing with an external pressure source.*

(g) *All gas vent lines shall be equipped with a scrubber or similar separation equipment.*

(2) *The following devices shall be installed and maintained in an operating condition at all times when the affected well (or wells) is producing. The operator shall maintain records on the structure or facility showing the present status and past history of each such device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.*

(a) *All well head assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.*

(b) *All flowlines from wellheads shall be equipped with high-low pressure sensors located close to the wellhead. The pressure sensors shall be set to activate the wellhead valve in the event of abnormal pressures in the flowline.*

(c) *All headers shall be equipped with check valves on the individual flowlines. The flowline and valves from each well located upstream of, and including, the header valves shall withstand the shut-in pressure of that well, unless protected by a relief valve with connections to bypass the header. If there is an inlet valve to a separator, the valve, flowline, and all equipment upstream of the valve shall also withstand shut-in wellhead pressure, unless protected by a relief valve with connections to bypass the header.*

(d) *All pneumatic, hydraulic, and other shut-in control lines shall be equipped with fusible material at strategic points.*

(e) *Remote shut-in controls shall be located on the helicopter deck and all exit stairway landings leading to the helicopter deck and to all boat landings. These controls shall be quick-operating devices.*

(f) *All pressure sensors shall be operated and tested for proper pressure settings monthly*

for at least four months. At such time as the monthly results are consistent, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(g) All automatic wellhead safety valves shall be tested for operation weekly. All automatic wellhead safety valves shall be tested for holding pressure monthly. If these results are consistent, a longer period of time between pressure tests, not to exceed quarterly, may then be approved by the Supervisor. In the event that any pressure testing sequence, exceeding monthly, reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(h) Check valves shall be tested for holding pressure monthly for at least four months. At such time as the monthly results are satisfactory, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(i) A complete testing and inspection of the safety system shall be witnessed by Geological Survey representatives at the time production is commenced. Thereafter, the operator shall arrange for a test every six months. The test shall be conducted when it can be witnessed by Geological Survey representatives.

(j) A standard procedure for testing of safety equipment shall be prepared and posted in a prominent place on the platform.

(3) Curbs, gutters, and drains shall be constructed and maintained in good condition in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into the ocean waters. Alternate methods to obtain the same results may be approved by the Supervisor. These systems shall not permit spilled oil to flow into the wellhead area.

(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails.

(5) The following requirements shall apply to the handling and disposal of all produced waste water discharged into the ocean waters overlying the submerged lands of the OCS. The disposal of waste water other than into these waters shall be approved by the Supervisor.

(a) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.

(b) Waste water disposal systems shall be designed and maintained to reduce the oil content of the disposed water to not more than fifty ppm. An effluent sampling station shall be located at a point prior to discharge into the receiving waters where a representative sample of the treated effluent can be obtained. On one day each month the effluent shall be sampled hourly for 8 hours and the following determinations shall be made on the composite sample: suspended solids, settleable solids, pH, total oil and grease content, and volume of sample obtained. Also the temperature of each hourly sample shall be recorded. All

samples shall be taken and all analyses for oil and grease content shall be performed in accordance with the latest edition of "Standard Methods for the Examination of Water and Wastewater", published by the American Public Health Association, Inc. The Supervisor may approve different methods for determination of oil and grease content if the method to be used is indicated to be reliable. A written report of the results shall be furnished to the Regional Office monthly. The report shall contain dates, time and location of sample, volumes of waste discharge on the date of sampling in barrels per day, and the results of the specific analysis and physical observations. A visual inspection of the appearance of the receiving waters in the discharge area shall be made daily and the results recorded and included in the monthly report.

(6) A firefighting system shall be installed and maintained in an operating condition in accordance with the following:

(a) A fixed automatic water spray system shall be installed in all wellhead areas. These systems shall be installed in accordance with the current edition of National Fire Protection Association's Pamphlet No. 15.

(b) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A firefighting system using chemicals may be considered for installation in certain areas in lieu of a firewater system in that area, if determined by the Supervisor to provide equivalent fire protection control.

(c) Pumps for the firewater systems shall be test-operated weekly. A record of the tests shall be maintained on a structure in the field and submitted semi-annually to the District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alternate firefighting system is provided.

(d) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(e) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the structure and a copy submitted to the District Office.

(7) An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance with the following:

(a) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are classified as hazardous areas as defined in API RP 500 A and B and the current edition of the National Electric Code.

(b) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located.

(c) The central control shall be capable of giving an alarm at a point not higher than 60 percent of the lower explosive limit.

(d) The central control shall automatically activate shut-in sequences and emergency equipment at a point not higher than 90% of the lower explosive limit.

(e) An application for the installation and maintenance of any gas detection system shall be filed with the appropriate District Office for approval. The application shall include the following:

(i) Type, location, and number of detection or sampling heads.

(ii) Cycling, non-cycling, and frequency information.

(iii) Type and kind of alarm including emergency equipment to be activated.

(iv) *Method used for detection of combustible gas.*

(v) *Method and frequency of calibration.*

(vi) *A diagram of the gas detection system.*

(vii) *Other pertinent information.*

(f) *A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the structure.*

(8) *The following requirements shall be applicable to all electrical equipment and systems installed:*

(a) *All gas and gasoline engines shall be equipped with low-tension ignition systems containing rigid connections and shielded wiring which shall prevent the release of sufficient electrical energy under normal or abnormal conditions to cause ignition of a combustible mixture.*

(b) *All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the current edition of the electrical code of the adjacent State, National Electric Code, and API RP 500 A and B, as appropriate. On mobile drilling structures, certificated by the Coast Guard, this equipment shall be installed, protected, and maintained in accordance with the applicable provisions of 46 CFR 110 through 113, inclusive.*

(c) *Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.*

(9) *Sewage disposal systems shall be installed and maintained in satisfactory operating condition in all cases where sewage is discharged into the ocean waters. Sewage is defined as human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes. Following sewage treatment, the effluent shall contain 50 ppm or less of biochemical oxygen demand (BOD), 150 ppm or less of suspended solids, and shall have a minimum chlorine residual*

of 1.0 mg/liter after a minimum retention time of fifteen minutes. Sewage treatment records shall be maintained and made available for inspection upon request. The records shall reflect the results of monthly tests. These tests shall include determination of BOD, suspended solids, and chlorine residual.

B. Welding Practices and Procedures. The following requirements shall apply to all structures, including mobile drilling structures, as applicable. The period of time during which these requirements are considered applicable to mobile drilling structures is the interval from the drilling out of the shoe of the conductor casing until the BOP stack and the marine riser are pulled in the process of final abandonment or suspension. For the purpose of this Order the term "welding and burning" is defined to include arc or acetylene welding and arc or acetylene cutting.

(1) All welding and burning shall be minimized.

(2) Such welding or burning as is necessary, on a structure, shall adhere to the following practices:

(a) Welding or burning on the structure should be done in an approved, properly functioning welding room; however, all welding and burning that is required but that cannot be prudently done in the welding room, shall be performed in compliance with the procedures outlined below.

(b) Prior to the commencement of any burning or welding operations, on a structure, the senior person in charge at the installation shall personally inspect the area in which the work is to be done. After this person has determined that it is safe to proceed, he shall issue a written authorization for the work. If both drilling and production operations are being conducted on the structure, the senior drilling man and the senior production man shall make this inspection and both shall sign it.

(c) A copy of each welding or burning authorization shall be maintained on the structure for a period of one year. These authorizations shall be made available, for inspection, to any authorized representative of the Geological Survey.

(d) During all welding or burning operations, one or more persons as necessary shall be designated as a "fire watch". Persons assigned to "fire watch" shall have no other duties while so assigned.

(e) The "fire watch" shall wear an item of distinctive clothing (vest or coat) for identification purposes and shall have in his immediate possession a portable gas detector and a portable fire extinguisher.

(f) If welding or burning must be done on containers, tanks, or other vessels which have contained a flammable substance, these objects shall be thoroughly cleaned and rendered free of such flammable substance before the work begins.

(g) If welding or burning must be done on in-service or connected-up piping, that section of pipe shall be isolated by tightly closed valves, blind flanges, or other suitable means, bled to atmospheric pressure, and thoroughly purged and cleaned to render it free of any flammable substance.

(h) If welding or burning must be done in confined spaces, the space shall be adequately vented and a continuous source of fresh air shall be supplied while work is in progress. If the fresh air is supplied by blowers, they shall be so positioned that the intakes will not pick up exhausted gases, fumes, or vapors.

(i) If any welding or burning is done on bulkheads, decks, or overheads, the adjacent, overlying, or underlying spaces shall be examined to determine that it is safe for the work to proceed. If deemed advisable, a second "fire watch" shall be employed in the contiguous area.

(j) *If any welding or burning must be done on structural members, it shall be determined by a competent authority that such welding or burning does not endanger the integrity of the structure.*

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

APPROVAL PROCEDURE FOR PIPELINES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) provides as follows:

> (b) The supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of section 250.18 or authorized under any lease issued or maintained under the act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

The operator shall comply with the following requirements. Platforms, fixed structures, and artificial islands are hereinafter referred to as structures. This Order does not apply to common carrier pipelines except as to that portion connected to or crossing a structure. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. General Design. All pipelines shall be designed and maintained in accordance with the following:

   A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a structure, including pipelines which are not operated or owned by the operator. Operators of structures installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) through (6) within 6 months of the effective date of this Order. The operator shall maintain records on the structure or facility showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, reinstallation or replacement.

(1) All oil and gas pipelines leaving a structure receiving production from the structure shall be equipped with a high-low pressure sensor to shut in the wells on the structure.

(2) All oil and gas pipelines delivering production to either offshore or onshore production facilities, or both, shall be equipped with an automatic shut-in valve, at or near the receiving facility, connected to an automatic and a remote shut-in system.

(3) All oil and gas pipelines coming onto a structure or delivering production to an onshore facility shall be equipped with a check valve or a quick-operating manual valve, as approved by the Supervisor, at or near the structure or facility to control backflow.

(4) All oil and gas pipelines crossing a structure which do not deliver production to the structure, but which may or may not receive production from the structure, shall be equipped with sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at or near the structure to avoid uncontrolled flow at the structure. This automatic shut-in valve shall be connected to either the structure automatic and remote shut-in system or to an independent remote shut-in system.

(5) All oil pumps and gas compressors shall be equipped with high-low pressure shut-in devices.

(6) All oil pipelines shall have a metering system to provide a continuous volumetric comparison of input to the line at the structure, or structures, with deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect significant variations between input and discharge volumes. In lieu of the foregoing, any system capable of detecting small leaks in the pipeline may be substituted with the approval of the Supervisor.

B. All oil and gas and other pipelines shall be protected from loss of metal that would endanger the strength and safety of the lines by methods such as protective coatings or cathodic protection.

C. *All oil and gas and other pipelines shall be installed and maintained to be compatible with trawling operations and other uses.*

D. *All oil and gas and other pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.*

E. *All oil and gas pipelines shall be maintained in good operating condition at all times and the ocean surface above the pipeline shall be inspected a minimum of once each week for indication of leakage using aircraft, floating equipment or other means. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the operator and submitted to the District Engineer annually by April 1. The operator shall immediately notify the District Engineer of any pipeline leak and within one week shall submit a report to him with respect to the cause, effect, and remedial action taken.*

F. *All oil and gas and other pipelines shall be designed and maintained for protection against water currents, storm scouring, soft bottoms, and other environmental factors.*

G. *An external inspection of all pipelines by side scan sonar or other means acceptable to the Supervisor shall be made at least once each year to identify all exposed portions of pipelines. All exposed portions of pipelines shall then be inspected in detail by photographic or other means acceptable to the Supervisor to determine if any hazards exist to the line or other users of the area. If a hazard is found to exist, appropriate corrective action shall be taken. Records of these inspections including the date, methods, and results of each inspection, shall be maintained by the operator and submitted to the District Engineer when the records become available.*

2. *Application. The operator shall submit in duplicate the following to the District Engineer for forwarding and approval by the Supervisor:*

A. *Drawing on a plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7) burial depth, if buried.*

B. A schematic drawing showing the location of the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, (3) check valves, and (4) the volumetric metering system.

C. General information concerning the pipeline including the following:

(1) Product or products to be transported by the pipeline.

(2) Size, weight and grade of the pipe.

(3) Length of line.

(4) Maximum water depth.

(5) Type or types of corrosion protection.

(6) Description of protective coating.

(7) Bulk specific gravity of line (with the line empty).

(8) Anticipated gravity or density of the product or products.

(9) Design working pressure and capacity.

(10) Maximum working pressure and capacity.

(11) Hydrostatic pressure and hold time to which the line will be tested after installation.

(12) Size and location of pumps and prime movers.

(13) Any other pertinent information as the Supervisor may prescribe.

3. Completion Report. The operator shall notify the District Engineer when installation of the pipeline is completed and submit a drawing, in duplicate, showing the location of the line as installed, accompanied by all hydrostatic test data, including procedure, test pressure, hold time, and results.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO PERMITTEES OF TWIN CORE HOLE PERMITS IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

DRILLING OF TWIN CORE HOLES

The Secretary of the Interior on November 3, 1965, approved the drilling of core holes on unleased lands of the Outer Continental Shelf off the coast of Southern California (30 Federal Register No. 218, Nov. 10, 1965). Authority was delegated to the Regional Oil and Gas Supervisor of the U. S. Geological Survey to approve the drilling of such wells provided (1) the core hole to be drilled is located within 100 feet of a well heretofore drilled under a State permit, or such greater distance from such a well as the Supervisor may prescribe where the prior drilled well is less than three geographical miles from the coastline, (2) the maximum depth to which a core hole may be drilled shall be the depth of the prior drilled well, (3) the approvals to drill core holes granted by the Supervisor shall be conditioned upon compliance with the regulations in 30 CFR Part 250, and such other reasonable requirements as he may prescribe, and (4) no approval to drill shall be granted until the applicant has posted an acceptable corporate surety bond in the amount prescribed in 43 CFR 3304.1, conditioned on compliance with all the requirements set forth in the permits to drill granted by the Supervisor.

In addition to the above, the permittee shall comply with the following requirements:

1. OCS Orders No. 1, 2, 3, 7, and 8 are hereby made applicable to core drilling operations.

2. An application for a general permit to conduct core drilling shall have been filed for approval prior to the filing of any applications to drill specific core holes.

3. A $300,000 corporate surety bond (Form 3380-3) covering Pacific Coast OCS operations shall have been filed.

4. Each application to drill a core hole (Form 9-331C in triplicate) shall be held in an open file in the Supervisor's office for 15 days after filing before approval may be granted. Only the application shall be considered public information.

5. The permittee shall: (a) obtain or have a geological survey blanket permit from the State to drill core holes within State waters, (b) obtain appropriate permission from the Army Corps of Engineers for the location of drilling ships (as provided in the Secretary of the Interior's Notice in 18 FR No. 186, Sept. 23, 1953).

6. All core hole locations shall be described by the Lambert Coordinate System for reference purposes applicable to the location in which it falls.

7. In each application to drill a twin core hole, the original State-permitted core hole shall be identified.

8. The permittee shall file a statement as to the exact location of the surface of the approved core hole and certify that it is within 100 feet of the original core hole at such time as drilling commences.

9. No directionally drilled core holes will be permitted.

10. Mud log and gas detector equipment shall be in operation while drilling below the shoe of the surface casing on twinned holes and below the shoe of the conductor casing on core holes offsetting the three-mile line not being drilled as a twin.

11. No down-hole formation fluid sampling equipment shall be operated at any time.

12. Conventional coring will be permitted either to total approved depth or such lesser depth as prescribed by the Supervisor provided the permittee of the original core hole being twinned has not filed an affidavit with the Supervisor stating that no conventional coring had been conducted in the original core hole. Sidewall sample coring may be conducted in that part of the hole in which an electric log has been run. Upon completion of operations the permittee shall file with the Supervisor a duly attested duplicate copy of the contractor's original log (tour sheet).

13. The permittee shall advise the District Engineer, Geological Survey, at least 48 hours prior to the drilling and reaching of the approved total depth. The "measuring out" of drill pipe at total depth will be witnessed by the District Engineer or his representative.

14. *The permittee shall not commence any abandonment operations prior to obtaining written approval from the District Engineer, Geological Survey. Abandonment of the core hole and clearing of the location of all obstructions on the ocean floor shall be witnessed by a representative of the Geological Survey.*

15. *Such other requirements as shall be prescribed in the general permit or the specific approved core hole application, or at any time such additional requirements are deemed necessary by the Supervisor or his representative.*

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
PACIFIC AREA

OCS ORDER NO. 11
Effective May 1, 1975

OIL AND GAS PRODUCTION RATES, PREVENTION OF WASTE, AND PROTECTION OF CORRELATIVE RIGHTS

This Order is established pursuant to the authority prescribed in 30 CFR 250.1, 30 CFR 250.11, and in accordance with all other applicable provisions of 30 CFR Part 250, and the Notice appearing in the Federal Register, dated December 5, 1970 (35 FR 18559), to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. This Order shall be applicable to all oil and gas wells on Federal leases in the Outer Continental Shelf of the Pacific Area. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). References in this Order to approvals, determinations, and requirements for submitting of information or applications for approval are to those granted, made, or required by the Oil and Gas Supervisor or his delegated representative.

1. Definition of Terms. As used in this Order, the following terms shall have the meanings indicated:

A. Waste of Oil and Gas. The definition of waste appearing in 30 CFR 250.2(h) shall apply, and includes the failure to timely initiate enhanced recovery operations where such methods would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. Enhanced recovery operations refers to pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

B. *Correlative Rights*. The opportunity afforded each lessee or operator to produce without waste his just and equitable share of oil and gas from a common source of supply.

C. *Maximum Efficient Rate (MER)*. The maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

D. *Maximum Production Rate (MPR)*. The approved maximum daily rate at which oil may be produced from a specified oil well completion or the maximum approved daily rate at which gas may be produced from a specified gas well completion.

E. *Interested Party*. The Operators and lessees, as defined in 30 CFR 250.2(f) and (g), of the lease or leases involved in any proceeding initiated under this Order.

F. *Reservoir*. An oil or gas accumulation which is separated from and not in oil or gas communication with any other such accumulation.

G. *Competitive Reservoir*. A reservoir as defined herein containing one or more producible or producing well completions on each of two or more leases, or portions thereof, in which the lease or operating interests are not the same.

H. *Property Line*. A boundary dividing leases, or portions thereof, in which the lease or operating interest is not the same. The boundaries of federally approved unit areas shall be considered property lines. The boundaries dividing leased and unleased acreage shall be considered property lines for the purpose of this Order.

I. *Oil Reservoir*. A reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

J. *Oil Well Completion*. A well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

K. *Gas Reservoir*. A reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

L. *Gas Well Completion*. A well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.

M. *Oil Reservoir with an Associated Gas Cap*. A reservoir that contains hydrocarbons in both a liquid and a gaseous state (two-phase).

N. *Producible Well Completion*. A well which is physically capable of production and which is shut-in at the wellhead or at the surface, but not necessarily connected to production facilities, and from which the operator plans future production.

2. *Classification of Reservoirs*.

A. *Initial Classification*. Each producing reservoir shall be classified by the operator, subject to approval by the Supervisor, as an oil reservoir, an oil reservoir with an associated gas cap, or a gas reservoir.

(1) The initial classification of each reservoir from which production is commenced subsequent to the date of this Order shall be submitted for approval with the initial submittal of MER data for the reservoir.

(2) Each reservoir from which production commenced on or prior to the date of this Order shall be classified by the operator, based on existing reservoir conditions. Such classification shall be determined and submitted to the Supervisor within six (6) months of the date of this Order.

B. *Reclassification*. A reservoir may be reclassified by the Supervisor, on his own initiative or upon application of an operator, during its productive life when information becomes available showing that such reclassification is warranted.

3. *Oil and Gas Production Rates*.

A. *Maximum Efficient Rate (MER)*. The operator shall propose a maximum efficient rate (MER) for each producing reservoir based on sound engineering and economic principles. When approved at the proposed or other rate, such rate shall not be exceeded, except as provided in paragraph 4 of this Order.

(1) Submittal of Initial MER. Within 45 days after the date of first production or such longer period as may be approved, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. Within six months after the date of this Order, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information for each reservoir from which production commenced prior to the date of this Order.

(2) Revision of MER. The operator may request a revision of an MER by submitting the proposed revision to the Supervisor on a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. The operator shall obtain approval to produce at test rates which exceed an approved MER when such testing is necessary to substantiate an increase in the MER.

(3) Review of MER. The MER for each reservoir will be reviewed by the operator annually, or at such other required or approved interval of time. The results of the review, with all current supporting information shall be submitted on a Request for Reservoir MER (Form 9-1866).

(4) Effective Date of MER. The effective date of an MER, or revision thereof, will be determined by the Supervisor and shown on a Request for Reservoir MER (Form 9-1866) when the MER is approved. The effective date for an initial MER shall be the first day following the completion of an approved testing period. The effective date for a revised MER shall be the first day following the completion of an approved testing period, or if testing is not conducted, the date the revision is approved.

B. Maximum Production Rate (MPR). The operator shall propose a maximum production rate (MPR) for each producing well completion in a reservoir together with full information on the method used in its determination. When an MPR has been approved for a well completion, that rate shall not be exceeded, except as provided in paragraph 4 of this Order. The MPR shall be based on well tests and any limitations imposed by (1) well tubing, safety equipment, artificial lift equipment, surface back pressure, and equipment capacity; (2) sand producing problems, (3) producing gas-oil and water-oil ratios; (4) relative structural position of the well

with respect to gas-oil or water-oil contacts; (5) position of perforated interval within total production zone; and (6) prudent operating practices. The MPR established for each well completion shall not exceed 110 percent of the rate demonstrated by a well test unless justified by supporting information.

(1) Submittal of Initial MPR. Within six months after the date of this Order, the operator shall submit a Request for Well Maximum Production Rate (MPR) (Form 9-1867), with the results of the potential test on a Well Potential Test Report (Form 9-1868). Thereafter, the operator shall have 30 days from the date of first continuous production within which to conduct a potential test, as specified under subparagraphs 5.B and 6.B of this Order, on all new and reworked well completions. Within 15 days after the date of the potential test, the operator shall submit a proposed MPR for the individual well completion on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), with the results of the potential test on a Well Potential Test Report (Form 9-1868). Extension of the 30-day test period may be granted. The effective date for any approved initial MPR shall be the first day following the test period. During the 30-day period allowed for testing, or any approved extensions thereof, the operator may produce a new or reworked well completion at rates necessary to establish the MPR. The operator shall report the total production obtained during the test period and approved extensions thereof, on the Well Potential Test Report (Form 9-1868).

(2) Revision of MPR Increase. If necessary to test a well completion at rates above the approved MPR to determine whether the MPR should be increased, notification of intent to test the well at such higher rates, not to exceed a stated maximum rate during a specified test period, shall be filed with the Supervisor. Such tests may commence on the day following the date of filing notification, unless otherwise ordered by the Supervisor. If an operator determines that the MPR should be increased he shall submit, within 15 days after the specified test period, a proposed increased MPR on a Request

for Well Maximum Production Rate (MPR) (Form 9-1867), and any other available data to support the requested revision, including the results of the potential test and the total production obtained during the test period on a Well Potential Test Report (Form 9-1868). Prior to approval of the proposed increased MPR, the operator may produce the well completion at a rate not to exceed the proposed increased MPR of the well. The effective date for any approved increased MPR shall be the first day following the test period. If testing rates or increased MPR rates result in production from the reservoir in excess of the approved MER, this excess production shall be balanced by underproduction from the reservoir under the provisions of subparagraph 4.B of this Order.

(3) Revision of MPR Decrease. When the quarterly test rate for an oil well completion or the semi-annual test rate for a gas well completion required under subparagraphs 5.C and 6.C of this Order is less than 90 percent of the existing approved MPR for the well, a new reduced MPR will be established automatically for that well completion equal to 110 percent of the test rate submitted. The effective date for the new MPR for such well completion shall be the first day of the quarter following the required date of submittal of periodic well-test results under subparagraphs 5.C and 6.C of this Order. Also, the operator may notify the Supervisor on a Request for Well Maximum Production Rate (MPR) (Form 9-1867) of, or the Supervisor may require, a downward revision of a well MPR at any time when the well is no longer capable of producing its approved MPR on a sustained basis. The effective date for such reduced MPR for a well completion shall be the first day of the month following the date of notification.

(4) Continuation of MPR. If submittal of the results of a quarterly well test for an oil completion or a semi-annual well test for a gas well completion, as provided for in subparagraphs 5.C and 6.C of this Order, cannot be timely, continuation of production under the last approved MPR for the well may be authorized, provided an extension of time in which to submit the test results is requested and approved in advance.

(5) Cancellation of MPR. When a well completion ceases to produce, is shut-in pending workover, or any other condition exists which causes the assigned MPR to be no longer appropriate, the operator shall notify the Supervisor accordingly on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), indicating the date of last production from the well, and the MPR will be canceled. Reporting of temporary shut-ins by the operator for well maintenance, safety conditions, or other normal operating conditions is not required, except as is necessary for completion of the Monthly Report of Operations (Form 9-152).

C. MER and MPR Relationship. The withdrawal rate from a reservoir shall not exceed the approved MER and may be produced from any combination of well completions subject to any limitations imposed by the MPR established for each well completion. The rate of production from the reservoir shall not exceed the MER although the summation of individual well MPR's may be greater than the MER.

4. Balancing of Production.

A. Production Variances. Temporary well production rates, resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation of this Order, and such production may be sold or transferred pursuant to paragraph 8 of this Order. However, when normal variations and fluctuations result in production in excess of a reservoir MER, any operator who is overproduced shall balance such production in accordance with subparagraph 4.B below. Such operator shall advise the Supervisor of the amount of such excess production from the reservoir for the month at the same time as Form 9-152 is filed for that month.

B. Balancing Periods. As of the first day of the month following the month in which this Order becomes effective, all reservoirs shall be considered in balance. Balancing periods for overproduction of a reservoir MER shall end on January 1, April 1, July 1, and October 1 of each year. If a reservoir

is produced at a rate in excess of the MER for any month, the operator who is overproduced shall take steps to balance production during the next succeeding month. In any event, all overproduction shall be balanced by the end of the next succeeding quarter following the quarter in which the overproduction occurred. The operator shall notify the Supervisor at the end of the month in which he has balanced the production from an overproduced reservoir.

C. Shut-in for Overproduction. Any operator in an overproduction status in any reservoir for two successive quarters which has not been brought into balance within the balancing period shall be shut-in from that reservoir until the actual production equals that which would have occurred under the approved MER.

D. Temporary Shut-in. If, as the result of storm, hurricanes, emergencies, or other conditions peculiar to offshore operations, an operator is forced to curtail or shut-in production from a reservoir, the Supervisor may, on request, approve makeup of all or part of this production loss.

5. Oil Well Testing Procedures.

A. General. Tests shall be conducted for not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall not begin until after recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation for any purpose. Measured gas volumes shall be adjusted to the standard conditions of the 15.025 psia and 60° F. for all tests. When orifice meters are used, a specific gravity shall be obtained or estimated for the gas and a specific gravity correction factor applied to the orifice coefficient. The Supervisor may require a prolonged test or retest of a well completion if such test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Supervisor may approve test periods of less than four hours and pretest stabilization periods of less than six hours for well completions, provided that test reliability can be demonstrated under such procedures.

B. *Potential Test*. Test data to establish or to increase an oil well MPR shall be submitted on a Well Potential Test Report (Form 9-1868). The total production obtained from all tests during the test period shall be reported on such form.

C. *Quarterly Test*. Tests shall be conducted on each producing oil well completion quarterly, and test results shall be submitted on a Quarterly Oil Well Test Report (Form 9-1869). Testing periods and submittal dates shall be as follows:

Testing Period	Latest Date for Submittal of Test Results	For Quarter Beginning
September 11 - December 10	December 10	January 1
December 11 - March 10	March 10	April 1
March 11 - June 10	June 10	July 1
June 11 - September 10	September 10	October 1

There shall be a minimum of 45 days between quarterly tests for an oil well completion.

6. *Gas Well Testing Procedures*.

A. *General*. Testing Procedures for gas well completions shall be the same as those specified for oil well completions in subparagraph 5.A except for the initial test which shall be a multi-point back-pressure test as described in paragraph 6.D.

B. *Potential Test*. Test data to establish or to increase a gas well MPR shall be submitted on a Well Potential Test Report (Form 9-1868).

C. *Semi-annual Test*. Tests shall be conducted on each producing gas well completion semi-annually, and test results shall be submitted on a Semi-annual Gas Well Test Report (Form 9-1870). Testing periods and submittal dates shall be as follows:

Testing Period	For Submittal of Test Results	For Semi-Annual Period Beginning
June 11 - December 10	December 10	January 1
December 11 - June 10	June 10	July 1

There shall be a minimum of 90 days between semi-annual tests for a gas well completion.

D. Back-Pressure Tests. *A multi-point back-pressure test to determine the theoretical open-flow potential of gas wells shall be conducted within thirty days after connection to a pipeline. If bottom-hole pressures are not measured, such pressures shall be calculated from surface pressures using the method, or other similar method, found in the Interstate Oil Compact Commission (IOCC) Manual of Back-Pressure Testing of gas wells. The results of all back-pressure tests conducted by the operator shall be filed with the Supervisor, including all basic data used in determining the test results. The Supervisor may waive this requirement if multi-point back-pressure test information has previously been obtained on a representative number of wells in a reservoir.*

7. Witnessing Well Tests. *The Supervisor may have a representative witness any potential or periodic well tests on oil and gas well completions. Upon request, an operator shall notify the appropriate District office of the time and date of well tests.*

8. Sale or Transfer of Production. *Oil and gas produced pursuant to the provisions of this Order, including test production, may be sold to purchasers or transferred as production authorized for disposal hereunder.*

9. Bottom-Hole Pressure Tests. *Static bottom-hole pressure test shall be conducted annually on sufficient key wells to establish an average reservoir pressure in each producing reservoir unless a different frequency is approved. The operator may be required to test specific wells. Results of bottom-hole pressure tests shall be submitted within 60 days after the date of the test.*

10. Flaring and Venting of Gas. *Oil- and gas-well gas shall not be flared or vented, except as provided herein.*

A. Small-Volume or Short-Term Flaring or Venting. *Oil- and gas-well gas may be flared or vented in small volumes or temporarily without the approval of the Supervisor in the following situations:*

(1) Gas Vapors. *When gas vapors are released from storage and other low pressure production vessels if such gas vapors cannot be economically recovered or retained.*

(2) *Emergencies.* During temporary emergency situations, such as compressor or other equipment failure, or the relief of abnormal system pressures.

(3) *Well Purging and Evaluation Tests.* During the unloading or cleaning up of a well and during drillstem, producing, or other well evaluation tests not exceeding a period of 24 hours.

B. *Approval for Routine or Special Well Tests.* Oil- and gas-well gas may be flared or vented during routine and special well tests, other than those described in paragraph A above, only after approval of the Supervisor.

C. *Gas-Well Gas.* Except as provided in A and B above, gas-well gas shall not be flared or vented.

D. *Oil-Well Gas.* Except as provided in A and B above, oil-well gas shall not be flared or vented unless approved by the Supervisor. The Supervisor may approve an application for flaring or venting of oil-well gas for periods not exceeding one year if (1) the operator has initiated positive action which will eliminate flaring or venting, or (2) the operator has submitted an evaluation supported by engineering, geologic, and economic data indicating that rejection of an application to flare or vent the gas will result in an ultimate greater loss of equivalent total energy than could be recovered for beneficial use from the lease if flaring or venting were allowed.

E. *Content of Application.* Applications under paragraph D above for existing operations, as of the date of this Notice, shall be filed within three months from the effective date of this Order. Applications under paragraph D(2) above shall include all appropriate engineering, geologic, and economic data in an evaluation showing that absence of approval to flare or vent the gas will result in premature abandonment of oil and gas production or curtailment of lease development. Applications shall include an estimate of the amount and value of the oil and gas reserves that

would not be recovered if the application to flare or vent were rejected and an estimate of the total amount of oil to be recovered and associated gas that would be flared or vented if the application were approved.

11. Disposition of Gas. The disposition of all gas produced from each lease shall be reported monthly on, or attached to, Form 9-152. The report shall be submitted in the following manner:

	Oil-Well Gas (MCF)	Gas-Well Gas (MCF)
Sales	______	______
Fuel	______	______
*Injected	______	______
Flared	______	______
Vented	______	______
Other (Specify)	______	______
Total	______	______

*Gas produced from the lease and injected on or off the lease.

12. Multiple and Selective Completions.

A. Number of Completions. A well bore may contain any number of producible completions when justified and approved.

B. Numbering Well Completions. Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir, or commingled reservoirs completion, the well completion number shall not change. Appendix A contains a detailed explanation of procedures for naming well completions.

C. Packer Tests. Multiple and selective completions shall be equipped to isolate the respective producing reservoirs. A packer test or other appropriate reservoir isolation test shall be conducted prior to or immediately after initiating production and annually thereafter on all multiply completed wells. Should the reservoirs in any multiply completed well become intercommunicative the operator shall make repairs and again conduct reservoir isolation tests unless some other operational procedure is approved. The results of all tests shall be submitted on a Packer Test (Form 9-1871) within 30 days after the date of the test.

D. *Selective Completions*. Completion equipment may be installed to permit selective reservoir isolation or exposure in a well bore through wireline or other operations. All selective completions shall be designated in accordance with subparagraph 12.B when the application for approval of such completions is filed.

E. *Commingling*. Commingling of production from two or more separate reservoirs within a common well bore may be permitted if it is determined that, collectively, the ultimate recovery will not be decreased. An application to commingle hydrocarbons from multiple reservoirs within a common well bore shall be submitted for approval and shall include reservoir engineering data, and a schematic diagram of well equipment. For all competitive reservoirs, notice of the application shall be sent by the applicant to all other operators of interest in the reservoirs prior to submitting the application to the Supervisor. The application shall specify the well completion number to be used for subsequent reporting purposes.

13. *Gas-Cap Well Completions*. All existing and future wells completed in the gas cap of a reservoir which has been classified and approved as an associated oil reservoir shall be shut-in until such time as the oil is depleted or the reservoir is reclassified as a gas reservoir; provided, however, that production from such wells may be approved when (1) it can be shown that such gas-cap production would not lead to waste of oil and gas, or (2) when necessary to protect correlative rights unless it can be shown that this production will lead to waste of oil and gas.

14. *Location of Wells*.

A. *General*. The location and spacing of all exploratory and development wells shall be in accordance with approved programs and plans required in 30 CFR 250.17 and 250.34. Such location and spacing shall be determined independently for each lease or reservoir in a manner which will locate wells in the optimum structural position for the most effective production of reservoir fluids and to avoid the drilling of unnecessary wells.

B. *Distance from Property Line.* An operator may drill exploratory or development wells at any location on a lease in accordance with approved plans; provided that no well drilled and completed after the date of this Order in which the completed interval is less than 200 feet from a property line shall be produced unless approved by the Supervisor. An operator requesting approval to produce a well in which the completed interval is located closer than 200 feet from a property line shall furnish the Supervisor with letters expressing acceptance or objection from operators of offset properties.

15. *Enhanced Oil and Gas Recovery Operations.* Operators shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. A plan for such operations shall be submitted with the results of the annual MER review as required in paragraph 3A(3) of this Order.

16. *Competitive Reservoir Operations.* Development and production operations in a competitive reservoir may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines, pursuant to 30 CFR 250.50 and delegated authority, that such agreements are practicable and necessary or advisable and in the interest of conservation.

A. *Competitive Reservoir Determination.* The Supervisor shall notify the operators when he has made a preliminary determination that a reservoir is competitive as defined in this Order. An operator may request at any time that the Supervisor make a preliminary determination as to whether a reservoir is competitive. The operators, within thirty (30) days of such preliminary notification or such extension of time as approved by the Supervisor, shall advise of their concurrence with such determination, or submit objections with supporting evidence. The Supervisor will make a final determination and notify the operators.

B. *<u>Development and Production Plans</u>. When drilling and/or producing operations are conducted in a competitive reservoir, the operators shall submit for approval a plan governing the applicable operations. The plan shall be submitted within ninety (90) days after a determination by the Supervisor that a reservoir is competitive or within such extended period of time as approved by the Supervisor. The plan shall provide for the development and/or production of the reservoir, and may provide for the submittal of supplemental plans for approval by the Supervisor.*

(1) *<u>Development Plan</u>. When a competitive reservoir is still being developed or future development is contemplated, a development plan may be required in addition to a production plan. This plan shall include the information required in 30 CFR 250.34. If agreement to a joint development plan cannot be reached by the operators, each shall submit a separate plan and any differences may be resolved in accordance with paragraph 17 of this Order.*

(2) *<u>Production Plan</u>. A joint production plan is required for each competitive reservoir. This plan shall include (a) the proposed MER for the reservoir; (b) the proposed MPR for each completion in the reservoir; (c) the percentage allocation of reservoir MER for each lease involved; and (d) plans for secondary recovery or pressure maintenance operations. If agreement to a joint production plan cannot be reached by the operators, each shall submit a separate plan, and any differences may be resolved in accordance with paragraph 17 of this Order.*

C. *<u>Unitization</u>. The Conservation Manager shall determine when conservation will be best served by unitization of a competitive reservoir, or any reservoir reasonably delineated and determined to be productive, in lieu of a development and/or production plan or when the operators and lessees involved have been unable to voluntarily effect unitization. In such cases, the Conservation Manager may require that development and/or production operations be conducted under an approved unitization*

plan. Within six (6) months after notification by the Conservation Manager that such a unit plan is required, or within such extended period of time as approved by the Conservation Manager, the lessees and operators shall submit a proposed unit plan for designation of the unit area and approval of the form of agreement pursuant to 30 CFR 250.51.

17. Conferences, Decisions and Appeals. Conferences with interested parties may be held to discuss matters relating to applications and statements of position filed by the parties relating to operations conducted pursuant to this Order. The Supervisor or Conservation Manager may call a conference with one or more, or all, interested parties on his own initiative or at the request of any interested party. All interested parties shall be served with copies of the Supervisor's or Conservation Manager's decisions. Any interested party may appeal decisions of the Supervisor or Conservation Manager pursuant to 30 CFR 250.81. Decisions of the Supervisor or Conservation Manager shall remain in effect and shall not be suspended by reason of any appeal, except as provided in that regulation.

F. J. Schambeck

F. J. Schambeck
Oil and Gas Supervisor
Pacific Area

Approved:

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

APPENDIX A

Subparagraph 12.B "Numbering Well Completions. Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir or commingled reservoirs completion, the well completion number shall not change. . ."

The intent of this Subparagraph is not necessarily to change the existing well completion names but to change the method of naming well completions after the effective date of this Order in order to insure that a completion in a given reservoir(s) and a specific well bore will be assigned a unique name and will retain the name permanently. For further clarification, the following guidelines and examples are offered:

1. Each well bore will have a distinct, permanent number.

2. Each reservoir or commingled reservoirs completion in a well bore will have a unique permanent designation which includes the well bore number in its nomenclature.

3. For the purpose of this Subparagraph, a "completion" is defined as all perforations in a given reservoir(s) in a specific well bore and is not necessarily associated with a tubing string or strings.

4. If more than one completion is made in a well bore, an alphabetical suffix must be used in the nomenclature to differentiate between completions.

5. An alphabetical prefix may be utilized to designate the platform from which the well will be produced.

Example No. 1: The first well drilled from the A Platform is a single completion.

Well No. A-1

(Should an operator wish to use an alphabetical suffix with a single completion, he may do so.)

Example No. 2: A well drilled by a mobile rig need not carry an alphabetical prefix.

Well No. 1

(If the well is later connected to and produced from a production platform, the well shall be redesignated to reflect an alphabetical prefix.)

__*Example No. 3:*__ *The second well drilled from the A Platform is a triple completion.*

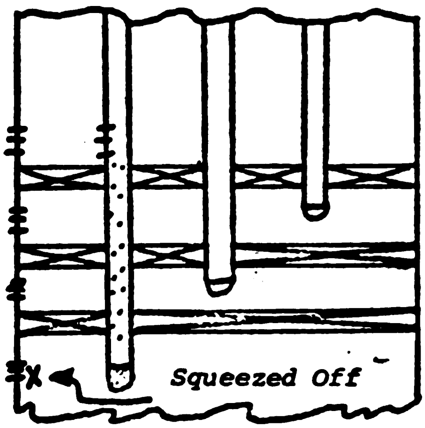
__*First Completion*__	__*Second Completion*__	__*Third Completion*__
A-2	***A-2-D***	***A-2-T***

(In the above example, the letters "D" and "T" were used in naming the second and third completions utilizing current industry practice, although the intent is not to restrict operators to the use of these particular alphabetical suffixes. Any alphabetical suffix may be used as long as it is unique to the completion in that reservoir or commingled reservoirs.

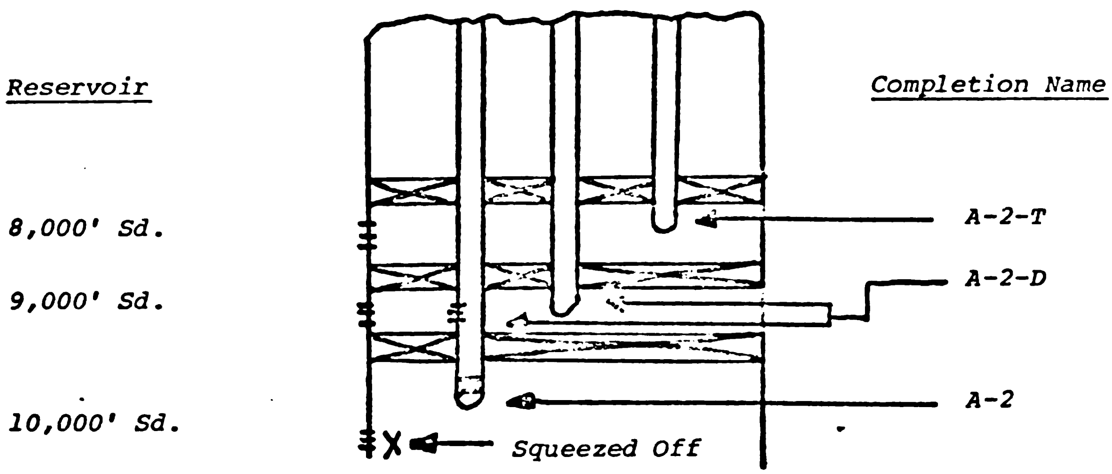
__*Example No. 4:*__ *The drawing is shown to illustrate the fact once a completion in a specific well bore is designated in a given reservoir(s), it will retain that name permanently. Let us consider the A-2 completion shown in Example No. 3. Should a recompletion be made in a different reservoir(s) at a later date, it shall be renamed; however, the production from the reservoir(s) associated with the original A-2 completion will always be identified with the A-2 completion. Once the A-2 completion in the 10,000' sand is squeezed and plugged off and the recompletion made to the 7,000' sand, the completion in the 7,000' sand would be designated A-2-A (or some other alphabetical suffix other than "D" or "T" presently associated with other completions in the 9,000' and 8,000' sands).*

The Sundry notice (Form 9-331) submitted to obtain approval for the workover shall be the vehicle for naming the new completion.

__*Reservoir*__	__*Completion Name*__
7,000' Sd.	*A-2-A*
8,000' Sd.	*A-2-T*
9,000' Sd.	*A-2-D*
10,000' Sd.	*A-2*



Example No. 5: *If the A-2 completion in Example No. 4 had been recompleted from the 10,000' sand to the 9,000' sand (where the A-2-D is currently completed), the completion would still be named A-2-D as both tubing strings would be considered one completion for purposes of this Order.*



UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
PACIFIC AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC AREA

OCS ORDER NO. 12
Effective December 1, 1974

PUBLIC INSPECTION OF RECORDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2 Section 250.97 of 30 CFR provides as follows:

Public Inspection of Records. Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the Supervisor determines that release of such information is required and necessary for the proper development of the field or area.

Section 2.2 of 43 CFR provides in part as follows:

Determinations as to Availability of Records. (a) Section 552 of Title 5, U. S. Code, as amended by Public Law 90-23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirements but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field

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1 Subsection (b) of section 552 provides that:
(b) This section does not apply to matters that are—
***
(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;

(9) Geological and geophysical information and data, including maps, concerning wells.

authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office of a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June 1967.

(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard.

The operator shall comply with the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Availability of Records Filed on or After the Effective Date of This Order. It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office, Los Angeles, California.

   A. Form 9-152 - Monthly Report of Operations. All information contained in this form shall be available except the information required in the Remarks column.

   B. Form 9-330 - Well Completion or Recompletion Report and Log.

      (1) Prior to commencement of production, all information contained on this form shall be available except Item 1a, Type of Well; Item 4, Location of Well, At top prod. interval reported below; Item 22, If Multiple Compl., How Many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

      (2) After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from the date of filing, Form 9-330 as required in 30 CFR 250.38(b), excluding the total of such time that operations and production are suspended by direction of the Secretary of the Interior or his duly authorized representative, and further excluding the total of such time that operations and production are stopped or prohibited by Court order, all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive of exceptions noted above, the lessee or operator shall file a Form 9-330 containing all information requested on the form, except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9-330.

C. Form 9-331 - Sundry Notices and Report on Wells. (1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. Form 9-331C - Application for Permit to Drill, Deepen or Plug Back. All information contained on this form and location plat attached thereto, shall be available except Item 4, Location of Well, at proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. Form 9-1869 - Quarterly Oil Well Test Report. All information contained on this form shall be available.

F. Form 9-1870 - Semi-Annual Gas Well Test Report. All information contained on this form shall be available.

G. Multi-Point Back Pressure Test Report. All information contained on the form used to report the results of required multi-point back pressure test of gas wells shall be available.

H. Sales of Lease Production. Information contained on monthly Geological Survey computer printout showing sales volumes value, and royalty of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. Filing of Reports. All reports on Form 9-152, 9-330, 9-331, 9-331C, 9-1869, 9-1870, and the forms used to report the results of multi-point back pressure tests, shall be filed in accordance with the following: All reports submitted on these forms after the effective date of this Order shall include a copy with the words "Public Information" shown on the lower right-hand corner. All items on the form not marked "Public Information" shall be completed in full; and such forms, and all attachments thereto, shall not be available for public inspection. The copy marked "Public Information" shall be completed in full, except that the items described in 1.A., B., C., and D. above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This copy of the form shall be made available for public inspection.

3. Availability of Records Filed Prior to December 1, 1974. Information filed prior to December 1, 1974, on Forms 9-152, 9-330, 9-331, and 9-331C is not in a form which can be readily made available for public inspection. Requests for information on these forms shall be submitted to the Supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

4. Availability of Inspection Records. All accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions are also available for public inspection.

F. J. Schambeck

F. J. Schambeck
Oil and Gas Supervisor
Pacific Area

Approved: November 21, 1974

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

ATTACHMENT C

registration. The Administrator concurs in that finding.

Judge Koutras recommended that Dr. Autore's registration be suspended for thirty-six months apparently to coincide with his period of probation. The Administrator does not accept this recommendation since in his view Dr. Autore's conduct reveals an absolute disregard of the public health and safety and his own responsibilities as a physician. Should Dr. Autore apply for a registration at some time in the future his application would be considered in the light of all the circumstances then obtaining. However, it is difficult at this time to see how the conduct resulting in his conviction could ever be ignored.

Therefore, under the authority vested in the Attorney General by Section 304 of the Comprehensive Drug Abuse Prevention and Control Act of 1970 (21 U.S.C. 824), and redelegated to the Administrator of the Drug Enforcement Administration, by § 0.100, as amended, Title 28 Code of Federal Regulations, the Administrator hereby orders that the Certificate of Registration of Guy M. Autore, M.D. (DEA Registration AA0091885) be, and hereby is, revoked, effective January 6, 1975.

Dated: December 30, 1974.

JOHN R. BARTELS, Jr.,
Administrator,
Drug Enforcement Administration.

[FR Doc.75-234 Filed 1-3-75;8:45 am]

INTERIM MANUFACTURING QUOTAS

Schedule I and II Controlled Substances

Section 306 of the Controlled Substances Act (21 U.S.C. 826) requires that the Attorney General establish aggregate production quotas for all controlled substances listed in Schedules I and II by July 1 of each year. This responsibility has been delegated to the Administrator of the Drug Enforcement Administration pursuant to § 0.100 of Title 28, Code of Federal Regulations.

Therefore, pursuant to section 306 and 21 CFR 1303.11 and 1303.21, any currently registered bulk manufacturer who received a manufacturing quota for 1974 for a basic class of Schedule I or II controlled substance and who has applied for a 1975 manufacturing quota for said substance, may manufacture, effective January 1, 1975, up to 25 percent of his 1974 bulk manufacturing quota. This notice is given to insure uninterrupted manufacture of Schedule I and II controlled substances pending publication of the 1975 manufacturing quotas.

Dated: December 30, 1974.

JOHN R. BARTELS, Jr.,
Administrator,
Drug Enforcement Administration.

[FR Doc.75-232 Filed 1-3-75;8:45 am]

Federal Bureau of Investigation

NATIONAL CRIME INFORMATION CENTER ADVISORY POLICY BOARD

Renewal

Notice is hereby given in accordance with the Federal Advisory Committee Act (Pub. L. 92-463) of the renewal of the NCIC Advisory Policy Board.

The Assistant Attorney General for Administration has determined that renewal of this Board is necessary and in the public interest. Copies of documents relating to the renewal of this Board and all documents and reports received pursuant to this notice will be available for inspection at FBI Headquarters, Washington, D.C., during regular business hours.

The nature and purpose of this Board is to recommend to the FBI general policy with respect to the philosophy, concept and operational principles of the NCIC.

Membership on this Board consists of twenty-six (26) representatives of criminal justice agencies throughout the United States. Twenty members are elected; five each from the four (4) NCIC geographic regions. Qualified electors are representatives of NCIC control terminal agencies. The FBI does not participate in the democratic electoral process. The six additional members are appointed by the Director of the FBI. They represent the judicial, prosecutive and corrections segements of the criminal justice community. The Chairman of the Board is elected by the membership at the first meeting of the Board and he will serve until January 4, 1977.

CLARENCE M. KELLEY,
Director.

[FR Doc.75-217 Filed 1-3-75;8:45 am]

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

RIVERTON UNIT, PICK-SLOAN MISSOURI BASIN PROGRAM, WYOMING

Sale of Lands

The sale of the lands described in the FEDERAL REGISTER published Friday, November 15, 1974, 39 FR 40311 is hereby postponed until further notice.

R. W. LLOYD,
Acting Regional Director.

[FR Doc.75-254 Filed 1-3-75;8:45 am]

Geological Survey

GULF OF ALASKA

Proposed OSC Orders

Notice is hereby given that the Geological Survey is proposing OCS Orders for the Gulf of Alaska. For purpose of these Orders, Gulf of Alaska shall include those lands subject to Federal OCS oil and gas leasing in that part of the North Pacific Ocean from the southernmost seaward boundary between Alaska and Canada to the westernmost point of the Alaska Peninsula, including the lower Cook Inlet.

By 39 FR 149, August 1, 1974, the Geological Survey announced its intention to develop operating orders for the Gulf of Alaska OCS Area and solicited comments concerning proposed OCS Orders by September 15, 1974. Comments have been received and considered.

In view thereof, the following operating orders are being proposed and consistent with current procedures of the Geological Survey, comments and suggestions are solicited as to the content of these proposed Orders.

OCS Order No. 1: **Marking of Wells, Platforms and Structures**
OCS Order No. 2: **Drilling Procedures**
OCS Order No. 3: **Plugging and Abandonment of Wells**
OCS Order No. 4: **Suspensions and Determination of Well Producibility**
OCS Order No. 5: **Installation of Subsurface Safety Devices**
OCS Order No. 6: **Procedures for Completion of Oil and Gas Wells**
OCS Order No. 7: **Pollution and Waste Disposal**
OCS Order No. 8: **Platforms and Structures**
OCS Order No. 9: **Approval Procedures for Oil and Gas Pipelines**
OCS Order No. 11: **Oil and Gas Production Rates, Prevention of Waste, and Protection of Correlative Rights**
OCS Order No. 12: **Public Inspection of Records**

Interested persons may submit written comments and suggestions to the Chief, Conservation Division, U.S. Geological Survey, National Center, Mail Stop 600, 12201 Sunrise Valley Drive, Reston, Virginia 22092, on or before March 1, 1975.

W. A. RADLINSKI,
Acting Director.

GULF OF ALASKA

[OCS Order No. 1]

MARKINGS OF WELLS, PLATFORMS AND STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.1[illegible] and in accordance with 30 CFR 250.3[illegible]. Section 250.37 provides as follows:

Well designations. The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Identification of fixed platforms and structures.* Platforms and structures shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inch[illegible]

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(30.5 cm.) in height with the name of the operator, the OCS lease number, the name of the area, the block number, and the platform or structure designation. The information may be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on lease OCS-A 1000 in Block 108 of Icy Bay Area.

The identifying sign on the platform would show:

BOC—OCS-A 1000—I.B.—108—C.

2. *Identification of mobile platforms and structures.* Floating semi-submersible platforms, bottom-setting mobile and floating drilling ships shall be identified by one sign with letters and figures not less than 12 inches (30.5 cm.) in height affixed to the derrick to be visible from off the vessel with the name of the lease operator, the OCS lease number, and the name of the area, and the block number.

3. *Identification of individual wells.* The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

RODNEY A. SMITH,
Oil and Gas Supervisor, Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS ORDER NO. 2]

DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.34, 250.41, 250.91, and the provisions of this Order which shall continue in effect until field drilling rules are issued. When sufficient geological and engineering information is obtained through exploratory drilling, operators may make application or the Supervisor may require an application for the establishment of field drilling rules. After field drilling rules have been established by the Supervisor, development wells shall be drilled in accordance with such rules.

All wells drilled under the provisions of this Order shall have been included in an exploratory or development plan for the lease as required under 30 CFR 250.34. Each Application for Permit to Drill (Form 9-331C) shall include all information required under 30 CFR 250.91, and shall include a notation of any proposed departures from the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

The Operator shall comply with the following requirements. All applications for approval under the provisions of the Order shall be submitted to the Supervisor.

1. *Well casing and cementing.* All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.14(a)(1), and the Application for Permit to Drill shall include the casing design safety factors for collapse, tension and burst. In cases where cement has filled the annular space back to the ocean floor, the cement may be washed out or displaced to a depth not exceeding 40 feet (12.2 metres) below the ocean floor to facilitate casing removal upon well abandonment. For the purpose of this Order, the casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing.

A temperature or cement bond survey shall be run following cementing of the surface, intermediate, and production casing strings to verify that the casing has been adequately cemented unless the cement is circulated to the ocean floor.

The design criteria for all wells shall consider all pertinent factors for well control, including formation fracture gradients, formation pressures and casing setting depths. All casing, except drive pipe, shall be new pipe or reconditioned used pipe that has been tested to insure that it will meet API standards for new pipe.

A. *Drive or structural casing.* This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet (30.5 metres) below the ocean floor or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement sufficient to fill the annular space back to the ocean floor shall be used.

B. *Conductor and surface casing.* Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons or other potential hazards and water depths.

(1) *Conductor casing.* This casing shall be set at a depth in accordance with paragraph 1B(3) below. A quantity of cement sufficient to fill the annular space back to the ocean floor shall be used.

(2) *Surface casing.* This casing shall be set at a depth in accordance with paragraph 1B(3) below and cemented in a manner necessary to protect all fresh-water sands and provide well control until the next string of casing is set.

This casing shall be cemented with a quantity sufficient to fill the calculated annular space to the ocean floor or at least 1,500 feet (457.2 metres) above the surface casing shoe and at least 200 feet (61.0 metres) inside the conductor casing or as approved by the Supervisor. When there are indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, the operator shall recement or make the necessary repairs. After drilling a maximum of 100 feet (30.5 metres) below the surface casing shoe, a pressure test shall be obtained to aid in determining a formation fracture gradient either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth of and maximum mud weight to be used in the intermediate hole.

(3) *Conductor and surface casing setting depths.* These strings of casing shall be set at the depth specified below, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations, provided, however, that the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure conditions, the Supervisor may prescribe the exact setting depth. Conductor casing setting depths shall be between 300 (91.4 metres) and 1,000 feet (304.8 metres) (TVD below ocean floor), and surface casing setting depths shall be between 1,000 (304.8 metres) and 4,500 feet (1,371.6 metres) (TVD below ocean floor).

Engineering, geophysical and geologic data used to substantiate the proposed setting depths of the conductor and surface casing (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

c. *Intermediate casing.* This string of casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The proposed setting depth for intermediate casing will be based on the pressure tests of the exposed formation immediately below the surface casing shoe or on subsequent pressure tests. This casing shall be set when the weight of the mud has been increased to within 0.5 ppg (0.06 kg/L) of the equivalent mud weight based on pressure tests below the surface casing.

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. If a liner is used as an intermediate string, it shall have a minimum lap length of 200 feet (61.0 metres). The cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. This test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

D. *Production casing.* This string of casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons,

but in any case, a calculated volume sufficient to fill the annular space at least 500 feet (152.3 metres) above the uppermost producible hydrocarbon zone must be used. When a liner is used as production casing, it shall have a minimum lap length of 200 feet (61.0 metres). The testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners. This test shall be recorded on the driller's log.

E. *Pressure testing of casing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed the internal yield pressure of the casing. The surface casing shall be tested, with water in the top 100 feet (30.5 metres) of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there are other indications of a leak, corrective measures shall be taken until a satisfactory test is obtained.

Casing	*Minimium surface pressure*
Conductor	200 (13.6 atm).
Surface	1,000 (68 atm).
Intermediate	1,500 (102 atms) or 0.2 lb/in²/ft. (0.045 atm /M), whichever is greater.
Liner	1,500 (102 atm) or 0.2 lb/in²/ft (0.045 atm /M), whichever is greater.
Production	1,500 (102 atm) or 0.2 lb/in²/ft (0.045 atm /M), whichever is greater.

After cementing any of the above strings, drilling shall not be commenced until a time lapse of eight hours under pressure for conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure are used. All casing pressure tests shall be recorded on the driller's log.

2. *Directional surveys.* Wells are considered vertical if inclination does not exceed an average of three degrees from the vertical. Inclination surveys shall be obtained on all vertical wells at intervals not exceeding 500 feet (152.4 metres) during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of three degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 500 feet (152.4 metres) during the normal course of drilling and at intervals not exceeding 100 feet (30.5 metres) in all angle change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 500 feet (152.4 metres) prior to, or upon, setting surface or intermediate casing, liners, and at total depth.

Composite directional surveys shall be filed with the Supervisor. The interval shown will be from the bottom of conductor casing, or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Lambert-Grid north shall be made after making the magnetic to true north correction.

3. *Blowout prevention equipment.* Blowout preventers and related well-control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the drive pipe or structural casing and until drilling operations are completed, blowout prevention equipment shall be installed and maintained ready for use as follows:

A. *Drive pipe or structural casing.* Before drilling below this string, at least one remotely controlled, annular-type blowout preventer or pressure-rotating, pack-off-type head and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. When the blowout preventer system is on the ocean floor, the choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, shall be used for diversion. An annular preventer or pressure-rotating, pack-off-type head, equipped with suitable diversion lines as described above and installed on top of the marine riser may be utilized to permit the diversion of hydrocarbons and other fluids. A diverter system which provides at least the equivalent of two 4-inch (10.2 cm.) lines (22 square inches (141.9 cm²) internal cross-sectional area) and full-open or butterfly valves shall be installed. The diverter system shall be equipped with automatic, remote-controlled valves which open, prior to shutting in the well, and at least two lines venting in different directions to accomplish downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9-331C) to the Supervisor for approval.

In drilling operations where a floating or semisubmersible type of drilling vessel is used and formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling conductor hole, a program which provides for safety in these operations shall be described and submitted to the Supervisor for approval. This program shall include all known pertinent and relevant information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, schematic diagram from rotary table to proposed conductor casing seat, and contingency plan for moving off location. Where drilling fluids are not circulated to the vessel, small diameter initial pilot hole shall be drilled from the bottom of the drive or structural casing to the proposed conductor casing seat to minimize hazards from shallow hydrocarbons.

B. *Conductor casing.* Before drilling below this string, at least one remotely controlled, annular-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. A diverter system as described in paragraph 3A above shall be installed.

C. *Surface casing.* Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remote-controlled, hydraulically operated blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one annular type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fill-up line.

D. *Intermediate casing.* Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) four remote-controlled, hydraulically operated blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least two equipped with pipe rams, one with blind rams, and one annular type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fill-up line.

E. *Testing.*—(1) *Pressure test.* Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, with the exception of the annular-type preventer, which shall be tested to 70 percent of the rated working pressure. They shall be tested: (a) when installed, (b) before drilling out after each string of casing is set, (c) not less than once each week from each of the control stations, and (d) following repairs that require disconnecting a pressure seal in the assembly.

(2) *Actuation.* While drill pipe is in use, ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The annular-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. An operable remote blowout-preventer-control station shall be provided, in addition to the one on the drilling floor.

(3) *Drills.* A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties.

(4) *Records.* All blowout preventer tests and crew drills shall be recorded on the driller's log.

F. *Other equipment.* An inside blowout-preventer assembly (back-pressure valve) and an essentially full-opening drill-string safety valve in the open position shall be maintained on the rig floor to fit all pipe in the drill string. A kelly cock shall be installed below the swivel, and an essentially full-opening

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‹elly cock of such design that it can be run through the blowout preventers shall be installed at the bottom of the kelly.

4. *Mud program.* The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. *Mud control.* Before starting out of the hole with drill pipe, the mud shall be properly conditioned by circulating with the drill pipe just off bottom until the annular volume is displaced, unless it is documented in the driller's log that: (1) there was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole, (2) the weight of the returning mud is not less than the weight of the mud entering the hole, and (3) other mud properties recorded on the daily drilling log are within the specified ranges at the stage of drilling the hole to perform their required functions. In those cases when the hole is circulated, the driller's log shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops 100 feet (30.5 metres). A mechanical device for measuring the amount of mud required to fill the hole shall be utilized, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall not be circulated and conditioned, except on or near bottom, unless well conditions prevent running the drill pipe back to bottom. The mud in the hole shall be circulated or reverse-circulated prior to pulling drill-stem test tools from the hole.

The hole shall be filled by accurately measured volumes of mud. The number of stands of drill pipe and drill collars that may be pulled between the times of filling the hole shall be calculated and posted. The number of barrels and pump strokes required to fill the hole for this designated number of stands of drill pipe and drill collars shall be posted. For each casing string, the maximum pressure which may be applied to the blowout preventer before controlling excess pressure by bleeding through the choke, shall be posted at the driller's station. Drill pipe pressure shall be monitored during the bleeding procedure for well control.

An operable degasser shall be installed in the mud system prior to the commencement of drilling operations and shall be maintained for use throughout the drilling and completion of the well.

B. *Mud system equipment.* Mud testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed at least once every eight hours, or more frequently as conditions warrant. Mud testing shall be conducted to determine the physical and chemical properties necessary to assure proper well control. Such tests shall be conducted in accordance with procedures outlined in API RP-13B, February 1974, and the results recorded and maintained at the drill site. The following mud system monitoring equipment shall be installed (with derrick floor indicators) and used at that time in the drilling operation when mud returns are first established and throughout subsequent drilling operations:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual and audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

(4) Gas-detecting equipment to monitor the drilling mud returns.

(5) Hydrogen sulfide (H_2S) sensing equipment capable of sensing a minimum of 5 parts per million of H_2S in air to monitor the drilling mud returns.

C. *Mud quantities.* The operator shall state in the Application for Permit to Drill, the minimum quantities of mud material, including weighting material, to be maintained at the drill site. For emergency use daily inventories shall be recorded and maintained at the drill site. Drilling operations shall be suspended in the absence of approved minimum quantities of mud materials.

5. *Supervision, surveillance and training.*

A. *Supervision.* The operator shall provide continuous company supervision of drilling operations on a 24-hour basis.

B. *Surveillance.* From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig floor surveillance at all times.

C. *Training.* Company and drilling contractor supervisory personnel including drillers shall be trained in and qualified for present-day well control. Records of such training and qualification shall be maintained at the drill site. Training shall include, but is not limited to:

(1) Abnormal pressure detection methods.

(2) Well control methods and procedures.

6. *Hydrogen Sulfide.* When drilling operations are undertaken to penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or, if unknown, upon encountering H_2S, the following preventive measures shall be taken to control the effects of the toxicity, flammability, and corrosive characteristics of H_2S. Alternative equipment or procedures that achieve the same or greater levels of safety may be approved by the Supervisor. When sulphur dioxide (SO_2), a product of combustion of H_2S, is present, the procedures outlined in the approved contingency plan required in paragraph 6A(3) of this Order shall be followed.

A. *Personnel safety and protection.*

(1) *Training Program.* (a) All personnel, whether regularly assigned, contracted, or employed on an unscheduled basis, shall be informed as to the hazards of H_2S and SO_2. They shall also be instructed in the proper use of personnel safety equipment and informed of H_2S detectors and alarms, ventilation equipment, prevailing winds, briefing areas, warning systems, and evacuation procedures.

(b) Information relating to these safety measures shall be prominently posted on the drilling facility and on vessels in the immediate vicinity which are serving the drilling facility.

(c) To promote efficient safety procedures, an on-site H_2S safety program, which includes a weekly drill and training session, shall be established. Records of attendance shall be maintained on the drilling facility.

(d) All personnel in the working crew shall have been indoctrinated in basic first-aid procedures applicable to victims of H_2S exposure. During subsequent on-site training sessions and drills, emphasis shall be placed upon rescue and first aid for H_2S victims. Each drilling facility shall have the following equipment, and each crew member shall be thoroughly familiar with the location and use of these items:

(i) A first-aid kit.

(ii) Resuscitators, complete with face masks, oxygen bottles, and spare oxygen bottles.

(iii) A Stokes litter or equivalent.

(e) One person, who regularly performs duties on the drilling facility, shall be responsible for the overall operation of the on-site safety and training program.

(2) *Visible warning system.* Wind direction equipment shall be installed at prominent locations to indicate to all personnel, on or in the immediate vicinity of the facility, the wind direction at all times for determining safe upwind areas in the event that H_2S is present in the atmosphere.

Operational danger signs shall be displayed from each side of the drilling ship or platform, and a number of rectangular red flags shall be hoisted in a manner visible to watercraft and aircraft. Each flag shall be of a minimum width of three feet (0.9 metres) and a minimum height of two feet (0.6 metres). Each sign shall have a minimum width of eight feet (2.4 metres) and a minimum height of four feet (1.2 metres), and shall be painted a high-visibility yellow color with black lettering of a minimum of 12 inches (30.5 cm.) in height. All signs and flags shall be illuminated under conditions of poor visibility and at night when in use. These signs and flags shall be displayed to indicate the following operational conditions and requirements:

(a) *Moderate danger.* When the threshold limit value of H_2S (10 parts per million) is reached, the signs will be displayed. If the concentration of H_2S reaches 20 parts per million, protective

breathing apparatus shall be worn by all personnel, and all non-working personnel shall proceed to the safe briefing areas.

(b) *Extreme danger.* When H_2S is determined to have reached the injurious level (50 parts per million), the flags shall be hoisted in addition to the displayed signs. All nonessential personnel or all personnel, as appropriate, shall be evacuated at this time. Radio communications shall be used to alert all known air- and watercraft in the immediate vicinity of the drilling facility.

(3) *Contingency plan.* A contingency plan shall be developed prior to the commencement of drilling operations and submitted to the Supervisor for approval. The plan shall include the following:

(a) General information and physiological response to H_2S and SO_2 exposure.

(b) Safety procedures, equipment, training, and smoking rules.

(c) Procedures for operating conditions:

(i) Moderate danger to life.

(ii) Extreme danger to life.

(d) Responsibilities and duties of personnel for each operating condition.

(e) Designation of briefing areas as locations for assembly of personnel during Extreme Danger condition. At least two briefing areas shall be established on each drilling facility. Of these two areas, the one upwind at any given time is the safe briefing area.

(f) Evacuation plan.

(g) Agencies to be notified in case of an emergency.

(h) A list of medical personnel and facilities, including addresses and telephone numbers.

(4) *H_2S detection and monitoring equipment.* Each drilling facility shall have an H_2S detection and monitoring system which activates audible and visible alarms before the concentration of H_2S exceeds its threshold limit value of 10 parts per million in air. This equipment shall be capable of sensing a minimum of five parts per million H_2S in air, with sensing points located at the bell nipple, shale shaker, mud pits, driller's stand, living quarters, and other areas where H_2S might accumulate in hazardous quantities.

H_2S detector ampules shall be available for use by all working personnel. After H_2S has been initially detected by any device, frequent inspections of all areas of poor ventilation shall be made with a portable H_2S–detector instrument.

(5) *Personnel protective equipment.*

(a) All personnel on a drilling facility or aboard marine vessels serving the facility shall be equipped with proper personnel protective-breathing apparatus. The protective-breathing apparatus used in an H_2S environment shall conform to all applicable Occupational Safety and Health Administration regulations and American National Standards Institute standards. Optional equipment, such as nose cups and spectacle kits, shall be available for use as needed.

(b) The storage location of protective-breathing apparatus shall be such that they are quickly and easily available to all personnel. Storage locations shall include the following:

(i) Rig floor.

(ii) Any working area above the rig floor.

(iii) Mud-logging facility.

(iv) Shale-shaker area.

(v) Mud pit area.

(vi) Mud storage area.

(vii) Pump rooms (mud and cement).

(viii) Crew quarters.

(ix) Each briefing area.

(x) Heliport.

(c) A system of breathing-air manifolds, hoses, and masks shall be provided on the rig floor and the briefing areas. A cascade air-bottle system shall be provided to refill individual protective-breathing-apparatus bottles. The cascade air-bottle system may be recharged by a high-pressure compressor suitable for providing breathing-quality air, provided the compressor suction is located in an uncontaminated atmosphere. All breathing-air bottles shall be labeled as containing breathing-quality air fit for human usage.

(d) Workboats attendant to rig operations shall be equipped with protective breathing apparatus for all workboat crew members. Pressure-demand or demand-type masks, connected to a breathing-air manifold, and additional protective breathing apparatus shall be available for evacuees. Whenever possible, boats shall be stationed upwind.

(e) Helicopters attendant to rig operations shall be equipped with a protective breathing apparatus for the pilot.

(f) The following additional personnel safety equipment shall be available for use as needed:

(i) Portable H_2S detectors.

(ii) Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas.

(iii) Chalk boards and note pads located on the rig floor, in the shale-shaker area, and in the cement pump rooms for communication purposes.

(iv) Bull horns and flashing lights.

(v) Resuscitators.

(6) *Ventilation equipment.* All ventilation devices shall be explosion-proof and situated in areas where H_2S or SO_2 may accumulate. Movable ventilation devices shall be provided in work areas and be multidirectional and capable of dispersing H_2S or SO_2 vapors away from working personnel.

(7) *Notification of regulatory agencies.* The following agencies shall be immediately notified under the alert conditions indicated:

(a) *Moderate danger.*

(i) U.S. Geological Survey.

(ii) U.S. Coast Guard.

(b) *Extreme danger.*

(i) U.S. Geological Survey.

(ii) U.S. Coast Guard.

(iii) Appropriate State agencies.

B. *Metallurgical equipment considerations.* Equipment used when drilling zones bearing H_2S shall be constructed of materials which, according to design principles, will be able to resist damage from the phenomena known variously as sulfide stress cracking, hydrogen embrittlement, or stress corrosion cracking. Such equipment includes drill pipe, casing, casing heads, blowout-preventer stack assemblies, kill lines, choke manifolds, and other related equipment. A knowledge of the various interations between stress, environment, and the metallurgy employed is required for successful operation in H_2S environments. The following general practices are required for acceptable performance:

(1) *Drill string.* Drill strings shall be designed consistent with the anticipated depth, conditions of the hole and reservoir environment to be encountered. Care shall be taken to minimize exposure of the drill string to high stresses as much as is practical and consistent with the anticipated hole conditions to be encountered.

(2) *Casing.* Casing, couplings, flanges, and related equipment shall be designed for H_2S service. Field welding on casing (except conductor and surface strings) is prohibited unless approved by the Supervisor.

(3) *Wellhead, blowout preventers, and pressure control equipment.* The blowout-preventer stack assembly shall be designed in accordance with criteria evolved through technology of the latest state-of-the-art for H_2S service. Surface equipment such as choke lines, choke manifold, kill lines, bolting, weldments, and other related well-killing equipment shall be designed and fabricated utilizing the most advanced technology concerning sulfide stress cracking. Elastomers, packing, and similar inner parts exposed to H_2S shall be resistant at the maximum anticipated temperature of exposure.

C. *Mud program.*

(1) Either water-base or oil-base muds are suitable for use in drilling formations containing H_2S. Disposal of drilling mud and cuttings shall be in accordance with OCS Order No. 7.

(2) A pH of 10.0 or above shall be maintained in a water-base mud system to control corrosion and prevent sulfide stress cracking.

(3) H_2S scavengers shall be used as needed in both water- and oil-base mud systems.

(4) Sufficient quantities of additives shall be maintained on location for addition to the mud system as needed to neutralize H_2S picked up by the system when drilling in formations containing H_2S.

(5) The application of corrosion inhibtors to the drill pipe to afford a protective coating or their addition to the mud system may be used as an additional safeguard to the normal protection of the metal by pH control and the scavengers mentioned above.

(6) Drilling mud containing H_2S gas shall be degassed at the optimum location for the particular rig configuration employed. The gases so removed shall be piped into a closed flare system and burned at a suitable remote stack.

D. *General operations.* All personnel in the working area shall utilize H_2S protective-breathing apparatus when required, as specified in paragraph 6A(2)(a). The normal fixed-point-monitor system in paragraph 6A(4) may be supplemented with portable H_2S detectors as conditions warrant.

(1) *Drill string trips or fishing operations.* Every effort shall be made to pull a dry drill string while maintaining well control. If it is necessary to pull the drill string wet after penetration of H_2S-bearing zones, increased monitoring of the working area shall be provided and protective-breathing apparatus shall be worn under conditions as outlined in paragraph 6A(2)(a).

(2) *Circulating bottoms-up from a drilling break, cementing operations, logging operations, or well circulation while not drilling.* After penetration of an H_2S-bearing zone, protective-breathing apparatus shall be worn by those personnel in the working area in advance of circulating bottoms-up or when H_2S is indicated by the monitoring system in quantities sufficient to require protective-breathing apparatus under paragraph 6A(2)(a), should this condition occur earlier.

(3) *Coring operations in H_2S-bearing zones.* Personnel protective-breathing apparatus shall be worn 10–20 stands in advance of retrieving the core barrel. Cores to be transported shall be sealed and marked for the pressure of H_2S.

(4) *Abandonment or temporary abandonment operations.* Internal well-abandonment equipment shall be designed for H_2S service.

(5) *Logging operations after penetration of known or suspected H_2S-bearing zones.* Mud in use for logging operations shall be conditioned and treated to minimize the effects of H_2S on the logging equipment.

(6) *Stripping operations.* Displaced mud returns shall be monitored and protective-breathing apparatus worn if H_2S is detected at levels outlined for protective-breathing apparatus under paragraph 6A(2)(a).

(7) *Gas-cut mud or well kick from H_2S-bearing zones.* Protective-breathing apparatus shall be worn when an H_2S concentration of 20 parts per million is detected. Should a decision be made to circulate out a kick, protective-breathing apparatus shall be worn prior to and subsequent to bottoms-up, and at any time during an extended kill operation that the concentration of H_2S becomes hazardous to personnel as defined in paragraph 6A(2)(a).

(8) *Drill string precautions.* Precautions shall be taken to minimize drill string stresses caused by conditions such as excessive dogleg severity, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint inbalance. API RP 7G (April 1974) shall be used as a guideline for drill string precautions. Tool joint compounds containing free sulphur shall be employed to minimize notching, stress concentrations, and possible drill pipe failures.

(9) *Flare system.* The flare system shall be designed to safely gather and burn H_2S gas. Flare lines shall be located as far from the drilling facility as feasible in a manner to compensate for wind changes. The flare system shall be equipped with a pilot and an automatic igniter. Backup ignition for each flare shall be provided.

E. *Kick detection and well control.* In addition to the requirements of paragraph 4B of this Order, all efforts shall be made to prevent a well kick as a result of gas-cut mud, drilling breaks, lost circulation, or trips for bit change. Drilling rate changes shall be evaluated for the possibility of encountering abnormal pressures, and mud weights adjusted in an effort to compensate for any hydrostatic imbalance that might result in a well kick.

In the event of a kick, the disposal of the well influx fluids shall be accomplished by one of the following alternatives, giving consideration to personnel safety, possible environmental damage, and possible facility well equipment damage:

Alternative A. To contain the well fluid influx by shutting in the well and pumping the fluids back into the formation.

Alternative B. To control the kick by using appropriate well-control techniques to prevent formation fracturing in open hole within the pressure limits of well equipment (drill pipe, casing, wellhead, blowout preventers, and related equipment). The disposal of H_2S and other gases shall be through pressured or atmospheric mud-gas separator equipment, depending on volume and pressure of H_2S gas. The equipment shall be designed to recover drilling mud and to vent to the atmosphere and burn the gases separated. The mud system shall be treated to neutralize H_2S and restore and maintain the proper mud quality.

F. *Well testing in an H_2S environment.*—(1) *Procedures.*

(a) Well testing shall be performed with a minimum number of personnel in the immediate vicinity of the rig floor and test equipment to safely and adequately perform the test and maintain related equipment and services.

(b) Prior to initiation of the test, special safety meetings shall be conducted for all personnel who will be on the drill facility during the test, with particular emphasis on the use of personnel protective-breathing apparatus, first-aid procedures, and the H_2S Contingency Plan.

(c) During the test, the use of H_2S detection equipment shall be intensified. All produced gases shall be vented and burned through a flare system which meets the requirements of paragraph 6D(9). Gases from stored test fluids shall be vented into the flare system.

(d) "No Smoking" rules in the approved Contingency Plan of paragraph 6A(3)(b) of this Order shall be rigorously enforced.

(2) *Equipment.*

(a) Drill-Stem test tools and wellhead equipment shall be suitable for H_2S service.

(b) Tubing which meets the requirements for H_2S service shall be used for drill-stem testing. Drill pipe shall not be used for drill-stem tests without the prior approval of the Supervisor. The water cushion shall be thoroughly inhibited in order to prevent H_2S corrosion. The test string shall be flushed with treated fluid for the same purpose after completion of the test.

(c) All surface test units and related equipment shall be designed for H_2S service. Only competent personnel who are trained in and knowledgeable of the hazardous effects of H_2S shall be utilized in these tests.

RODNEY A. SMITH,
*Oil and Gas Supervisor,
Alaska Area.*

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS Order No. 3]

PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations shall not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Permanent Abandonment.*—A. *Isolation in uncased hole.* In uncased portions of wells, cement plugs shall be spaced to extend 100 feet (30.5 metres) below the bottom to 100 feet (30.5 metres) above the top of any oil, gas, and water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata. Additional cement plugs may be required to protect other minerals. No more than 2500 feet (762.5 metres) of uncased hole shall be left without a cement plug of at least 100 feet (30.5 metres) in length.

B. *Isolation of open hole.* Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below. In the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 100 feet (30.5 metres) above and 100 feet (30.5 metres) below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 50 feet (15.2 metres) nor more than 100 feet

(30.5 metres), above the casing shoe with a cement plug calculated to extend at least 100 feet (30.5 metres) below the casing shoe and 50 feet (15.2 metres) above the retainer.

(3) A permanent type bridge plug set within 150 feet (45.7 metres) above the casing shoe with 50 feet (15.2 metres) of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. *Plugging or isolating perforated intervals.* A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet (30.5 metres) above and 100 feet (30.5 metres) below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet (45.7 metres) above the open perforations with 50 feet (15.2 metres) of cement on top may be used, provided the perforations are isolated from the hole below.

D. *Plugging of casing stubs.* If casing is cut and recovered, a cement plug 200 feet (61.0 metres) in length shall be placed to extend 100 feet (30.5 metres) above and 100 feet (30.5 metres) below the stub. A retainer may be used in setting the required plug.

E. *Plugging of annular space.* No annular space that extends to the ocean floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. *Surface plug requirement.* A cement plug of at least 150 feet (45.7 metres) with the top of the plug 150 feet (45.7 metres) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the surface.

G. *Testing of plugs.* The setting and location of the first plug below the top 150 foot (45.7 metres) surface plug and each plug placed opposite open hole or perforations, shall be verified by placing a minimum pipe weight of 15,000 pounds (6803.9 kilograms) on the plug.

H. *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. *Clearance of location.* All casing and piling shall be severed and removed to at least 15 feet (4.6 metres) below the ocean floor and the ocean floor shall be cleared of any obstructions.

2. *Temporary abandonment.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements F and I of paragraph 1 above. When casing extends above the ocean floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 feet (4.6 metres) and 200 feet (61.0 metres) below the ocean floor.

RODNEY A. SMITH,
Oil and Gas Supervisor, Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS Order No. 4]

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved. Any application for suspension of production for an initial period shall be submitted prior to the expiration of the term of a lease. The Supervisor may approve a suspension of production provided at least one well has been drilled on the lease and he determines it to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

To provide data necessary to determine that a well may be capable of production in paying quantities, the following are minimum requirements:

1. *Oil wells.* A production test of at least two hours duration after the well flow has stabilized.

2. *Gas wells.* A deliverability test of at least two hours duration after the well flow has stabilized, or a four-point back pressure test.

3. *Well data.* All pertinent engineering, geologic and economic data shall be submitted to the Supervisor and will be considered in determining whether a well is capable of being produced in paying quantities.

4. *Witnessing and results.* All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained.

RODNEY A. SMITH,
Oil and Gas Supervisor, Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS ORDER NO. 5]

SUBSURFACE SAFETY DEVICES

This order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

(b) *Completed wells.* In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the Supervisor's office. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a surface or other remotely controlled subsurface safety device installed at a depth of 100 feet (30.5 metres) or more below the ocean floor unless, after application and justification, the well is determined to be incapable of flowing oil or gas. These installations shall be made within two (2) days after stabilized production is established, and during this period of time the well shall not be left unattended while open to production.

A. *Shut-in wells.* A tubing plug may be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six (6) months. Such plugs shall be set at a depth of 100 feet (30.5 metres) or more below the ocean floor. All retrievable plugs shall be of the pumpthrough type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two (2) days after completion.

B. *Injection wells.* Subsurface safety devices shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing oil or gas, which condition shall be verified annually.

2. *Design, testing and inspection.* Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

A. *Surface-controlled subsurface safety devices.*—(1) *Quality Assurance and Performance.* The operator shall comply with the minimum standards set forth in API Spec. 14 A, October 1973, Subsurface Safety Valves, for quality assurance including design, material, and functional test requirements, and for verification of independent party performance testing and manufacturer functional testing of such valves.

(2) *Installation and testing.* The operator shall comply with the minimum recommended practices set forth in API

P 14 B, October 1973, Design, Installation, and Operation of Subsurface Safety Valve Systems, which contain procedures for design calculations, safe installation, and operating and testing. Each surface-controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed and thereafter at intervals not exceeding days. If the device does not operate properly, it shall be removed, repaired, and reinstalled or replaced and tested to insure proper operation.

B. *Tubing plugs.* A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding six (6) months. If a test indicates leakage, the plug shall be removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

3. *Temporary removal.* Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authority or notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9-331) for a period not to exceed fifteen (15) days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production.

4. *Additional protective equipment.* All tubing installations in which a wireline- or pumpdown- retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system.

5. *Emergency action.* All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such device or plug shall be promptly installed with due consideration being given to personnel safety.

6. *Records.* The operator shall maintain the following records for a minimum period of one year for each subsurface safety device and tubing plug installed, which records shall be available to any authorized representative of the Geological Survey.

A. *Field records.* Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:

(1) A record which will give design and other information; i.e., make, model, size, etc.

(2) Verification or assembly by a qualified person in charge of installing the device and installation date.

(3) Verification of setting depth and all operational tests as required in this Order.

(4) Removal date, reason for removal, and reinstallation date.

(5) A record of all modifications of design in the field.

(6) All mechanical failures or malfunctions, including sandcutting, of such devices, with notation as to cause or probable cause.

(7) Verification that a failure report was submitted.

B. *Other records.* The following records, as a minimum, shall be maintained at the operator's office:

(1) Verified design information of subsurface safety devices for the individual well.

(2) Verification of assembly and installation according to design information.

(3) All failure reports.

(4) All laboratory analysis reports of failed or damaged parts.

(5) Quarterly failure-analysis report.

7. *Reports.* Well completion reports (Form 9-330) and any subsequent reports of workover (Form 9-331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed.

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the office of the Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The reports shall be submitted within 30 days following the periods ending December 31, March 31, June 30, and September 30 of each year.

RODNEY A. SMITH,
Oil & Gas Supervisor Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS Order No. 6]

COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12 (b).

1. *Wellhead equipment and testing.* A. *Wellhead equipment.* All completed wells shall be equipped with casingheads, wellhead fittings, valves, and connnections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two masters valves shall be installed on the tubing in all wells. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to 1.5 times the rated working pressure of the fitting to be installed.

B. *Testing procedure.* Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied to the production casing string. Should the pressure at the casinghead reflect the applied pressure, corrective measures must be taken and the casing shall again be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. *Multiple or tubingless completions.—A Multiple completions.*

(1) Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

(2) When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.

B. *Tubingless completions.*

(1) All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.

(2) The tubing string(s) shall be new pipe or reconditioned used pipe that has been tested to insure that it will meet API Standards for new pipe. The tubing shall be cemented with a sufficient volume to extend a minimum of 500 feet (152.4 metres) above the uppermost producible zone.

(3) Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

RODNEY A. SMITH,
Oil and Gas Supervisor, Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS Order No. 7]

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority perscribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. Section 250.43 provides as follows:

(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and non-liquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the

lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant, the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with subsection (b) above, shall be governed by applicable law.

NOTE.—In paragraph (a) above, the Regional Director of the Federal Water Pollution Control Administration has been replaced by the Regional Administrator, Environmental Protection Agency.

All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Pollution prevention.* The disposal of waste materials into ocean waters shall not create conditions which will adversely affect the public health, life or property, aquatic life or wildlife, recreation, navigation, or other uses of the ocean waters. All applicable waste disposal regulations administered by the Environmental Protection Agency shall be complied with in all cases where such regulations are more stringent than the requirements of this Order. All personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. The operator shall comply with the following pollution prevention requirements:

A. *Liquid disposal.*

(1) Drilling mud containing oil shall not be disposed of into the ocean water. Drilling mud containing toxic substances shall be neutralized prior to disposal.

(2) All platforms and structures shall be curbed and connected by drains to a collecting tank or sump unless drip pans, or equivalents, are placed under equipment and piped to a tank or sump as provided in OCS Order No. 8.

(3) The following requirements shall apply to the handling and disposal of all produced water discharged into the ocean water. The disposal of water other than into the ocean water shall have the method and location approved by the Supervisor.

(a) Produced waste water disposal systems shall be designed and maintained so that the oil content of the effluent shall not exceed 50 mg/1 determined by averaging the four samples required in (b)(i) below. The oil content shall be determined by the infrared or fluorometric method. A copy of the method to be used shall be submitted to the Supervisor for approval. The Supervisor may approve the use of other methods, if the method to be used at a location is shown to be reliable under the conditions existing at that location.

(b) Produced water discharged into the ocean will be sampled, analyzed, and the results of the analysis recorded once each month to determine if the requirement of subparagraph 1A(3)(a) above is fulfilled. Testing and reporting procedures are as follows:

(i) Four samples shall be collected over a 24-hour period. At least two hours must elapse between grabbed samples; however, a continuous sample is acceptable in lieu of grabbed samples. Sample, grabbed or continuous, shall be taken at a point prior to contact with seawater and shall be as nearly representative of the discharge stream as possible.

(ii) Analysis of the effluent sample shall be completed within two weeks of collection, or a new set of samples must be taken.

(iii) When the sample is taken, the date, time of day, temperature of discharge, pH, and discharge in bbls/day shall be recorded. This information, along with the analysis results, shall be reported on Form —— "Quality Measurement of Discharged Produced Water."

(iv) A copy of the latest analysis results shall be maintained at the discharge site or field production headquarters.

(v) For each produced water discharge point, a quarterly report of the results of each monthly analysis shall be submitted to the Supervisor. Reports shall be submitted in January, April, July, and October of each calendar year.

(c) Should the analysis indicate that the effluent does not meet the requirement of paragraph 1A(3)(a) above, corrective action shall immediately be taken. Approval to continue operations to aid in the identification and remedy of the problem must be obtained from the Supervisor. Such approval shall be contingent upon submittal of a follow-up report to the Supervisor within 10 days.

B. *Solid waste disposal.*

(1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the ocean water unless the oil has been removed.

(2) Mud containers and other solid waste materials shall be incinerated or transported to shore for disposal in accordance with Federal, State or local requirements.

(3) Sewage disposal systems shall be installed and used in all cases where sewage is discharged into the ocean water. Sewage is defined as water containing liquid and solid wastes from toilets and other receptacles intended to receive or retain body wastes.

(a) Sewage disposal systems shall be designed and maintained so that the effluent shall meet secondary treatment standards as follows:

(i) Biochemical oxygen demand (BOD) of 50 mg/l or less, to be determined by the procedure in Standard Methods, 13th Edition, 1971 p. 489 Method 219.

(ii) Suspended solids of 150 mg/l, to be determined by the procedure in Standard Methods, 13th Edition, 1971, p. 537 Method 224c.

(iii) Minimum chlorine residual of 1.0 mg/l, to be determined by the procedure in Standard Methods, 13th Edition, 1971 p. 382, Method 204A or 204B. Other methods, such as ultraviolet light, may be approved upon application.

(b) Where sewage effluent is discharged into the ocean water, the operator shall comply with the following:

(i) The effluent shall be sampled and analyzed, and the results recorded semiannually to determine if the requirement under subparagraph 1B(3)(a) above are being met.

(ii) A copy of the most recent laboratory analysis of the effluent shall be maintained at the field headquarters or at the discharge site.

(iii) The semi-annual effluent analysis results shall be submitted to the Supervisor in January and July of each calendar year.

(iv) Should analysis indicate that the effluent does not meet the requirements of paragraph 1B(3)(a) above, immediate corrective action shall be taken.

2. *Inspections and reports.* The operator shall comply with the following pollution inspection and reporting requirements and with Orders issued by the Supervisor for the control or removal of pollutants:

A. *Pollution inspections.* All drilling and production facilities shall be inspected daily. Such maintenance or repairs as are necessary to prevent pollution of ocean water shall immediately be performed.

B. *Pollution reports.*

(1) All spills of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the Supervisor. All spills of less than 15 barrels (2.1 metric tons) shall be reported orally to the Supervisor within 12 hours and shall be confirmed in writing.

(2) All spills of oil and liquid pollutants of 15 to 50 barrels (2.1 to 7.1 metric tons) shall be reported orally to the Supervisor immediately and shall be confirmed in writing.

(3) All spills of oil and liquid pollutants of a substantial size or quantity which is defined as more than 50 barrels (7.1 metric tons), and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the Supervisor, the Coast Guard, and the Regional Administrator

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Environmental Protection Agency. All oral reports shall be confirmed in writing.

(4) Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.

3. *Control and removal.*—A. *Corrective action.* Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for each lease for initiating corrective action to control and remove pollution and such plan shall be filed with the Supervisor. Corrective action taken under the plan shall be subject to modification when directed by the Supervisor.

B. *Equipment.* Standby pollution control equipment and materials shall be maintained by, or shall be available to, each operator at an offshore or onshore location. This shall include containment booms, skimming apparatus, clean-up materials and chemical agents, and shall be available prior to the commencement of operations. No chemicals shall be used without prior approval of the Supervisor. A list of equipment, material, their location, and the time required for deployment shall be approved for each lease operation by the Supervisor. The equipment and materials shall be inspected monthly and maintained in good condition for use. The results of the inspections shall be recorded and maintained at the site.

RODNEY A. SMITH,
Oil and Gas Supervisor,
Alaska Area.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

U.S.G.S. OIL AND GAS CONSERVATION DIVISION

QUALITY MEASUREMENTS OF DISCHARGED PRODUCED WATER

OPERATOR:

LOCATION:

OCS LEASE # OCS BLOCK AND AREA

FIELD NAME PLATFORM NAME

COLLECTION:

	1 (m d y)	2 (m d y)	3 (m d y)	4 (m d y)
DATE				
TIME 24 hrs.				
DISCHARGE bbls/dy				

ANALYSIS:

	(m d y)	(m d y)	(m d y)	(m d y)
DATE				
METHOD				
PARAMETER RESULTS				
TEMP. °F				
pH				
VOL. ml				
OIL CONTENT mg/L				
AVERAGE mg/L				

LAB:__________ ATTEST:__________

GULF OF ALASKA

[OCS ORDER NO. 8]

PLATFORMS, STRUCTURES AND ASSOCIATED EQUIPMENT

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraphs (a) and (b) of § 250.18 or authorized under any lease issued or maintained under the Act.

The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms and structures, including all facilities installed on a platform or structure, whether or not operated or owned by the operator. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the Supervisor. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. *Design, application and certification.*—A. *Platform design.*

(1) *General design.* A platform or structure shall be designed for safe installation and operation for its intended use and service life at a specific site. Steel structures shall be designed in accordance with the provisions of API RP 2A, January 1974, Planning Designing and Constructing Fixed Offshore Platforms, that are not in conflict with this Order. The design of structures other than steel shall be evaluated on an individual basis. Consideration shall be given to conditions which may contribute to structural damage such as:

(a) Wind, wave, tidal, current, ice, and seismic forces and other environmental loading forces.

(b) Functional loading conditions including the weight of the structure and all permanently fixed equipment, and the effects of static and dynamic functional load conditions during installation and the designed operational service period.

(c) Water depth, topography, surface and subsurface soil conditions, slope stability, scour conditions and other pertinent geologic conditions based on information from on-site investigations.

(2) *Isolation of facilities.* All platforms and structures shall be designed to isolate and protect living quarters from well and production facilities.

B. *Application.* Prior to construction of a fixed platform or structure, the operator shall submit for approval, in duplicate, an application showing all essential features of the platform or structure and supporting design information including the following:

(1) *General information.*

(a) Identification data, which shall include the platform or structure designation, lease number, area name, block number, and operator.

(b) Location data including plat with coordinates in longitude and latitude, and Universal Transverse Mercator Coordinates and the distance from the nearest block and lease lines.

(c) Primary use and other intended functions including planned drilling and production operations, storage, etc.

(d) Personnel facilities, personnel access of transfer and material handling

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plans including living quarters, boat landings, heliports.

(e) Procedures for installation of the platform or structure and its foundation.

(f) Operational plans including a description of each phase of operation and planned simultaneous operations for the service life of the platform or structure.

(g) The application should include design drawings and plats to clearly illustrate all essential parts, dimensions, and specifications of the platform or structure and the foundation.

(2) *Environmental information.*

(a) Description of all pertinent environmental data which may have a bearing on the installation, operation or design of the platform or structure including the source of the data.

(b) Information on the type and magnitude of the design environmental loading conditions.

(3) *Foundations.*

(a) Information on methods and extent of on-site investigations and tests including the results and supporting data.

(b) A description of foundation loads and loading conditions.

(4) *Design features.*

(a) A description of the critical design loading and design criteria taking into consideration maximum environmental and operational loading conditions expected over the service life of the platform or structure. This shall include those conditions considered under paragraph 1. A. (1) (a), (b), and (c), above.

(b) For steel structures, a description of the materials, specification, strength analyses, and allowable stresses over the design service life.

(c) For concrete structures, a description of the materials, specification, strength and serviceability requirements and analysis of the reinforcing systems.

(d) An analysis of slope and soil stability in relation to the foundation and the foundation design loads.

(e) Method of corrosion protection.

C. *Certification.*

(1) Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

(2) The following certifications, signed and dated by a company representative shall accompany the application.

(a) Operator certifies that this platform has been certified by a registered professional engineer and the structure will be constructed, operated and maintained as described in the application, and any approved modification thereto. Certified Plans are on file at ________________.

(b) Certification that the mechanical and electrical systems of the facility will be designed and installed under the supervision of a registered professional engineer. Maintenance of these systems will be by qualified personnel.

D. *Design features of production facilities.* Information relative to design features as follows shall be submitted in duplicate prior to installation.

(1) A flow schematic showing size, capacity, and design working pressure of separators, treaters, storage tanks, compressors, pipeline pumps, and metering devices.

(2) A schematic diagram showing pollution and safety control equipment identified according to nomenclature (Definition, Symbols and Identification) contained in API RP 14C, June 1974, Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms, accompanied by an explanation as to the function and sequence of operation.

(3) A schematic piping diagram showing the size and design working pressure with reference to welding specification(s) or code(s) used.

(4) A diagram of the fire-fighting system.

(5) Electrical system information shall include the following:

(a) Plan view of each platform deck outlining any nonhazardous area—areas which are unclassified with respect to electrical equipment installations, and areas in which potential ignition sources, other than electrical are to be installed. The area outline should include the following:

i. Any surrounding production or other hydrocarbon source and a description of deck, overhead and firewall.

ii. Location of generators, control rooms, panel boards, major cabling—conduit routes and identification of wiring method.

(b) One line electrical schematic which includes the following information:

i. Type, rating and the operating and safety controls of generators and prime movers.

ii. Main generator switchboard including interlocks, controls and indicators.

iii. Feeder and branch circuits, including circuit load, wire type and size, motor running protection and circuit breaker setting.

(c) Elementary electrical schematic of any platform safety-shutdown system with functional legend.

2. *Operations on platforms and structures.— A. Safety and Pollution Control Equipment and Procedures.* Operators of fixed platforms and structures shall comply with the following requirements. Any device on wells, vessels, or flowlines temporarily out of service shall be flagged. Safety devices and systems on wells which are capable of producing shall not be bypassed or locked out of service unless necessary during start-up or maintenance operations, and then only with personnel on duty aboard the platform.

(1) *Shut-in devices.* The followisg shut-in devices shall be installed and maintained in an operating condition on all vessels and water separation facilities when such vessels and separation facilities are in service.

(a) All separators shall be equipped with high and low pressure shut-in sensors and a relief valve. Vessels connected together by a system of adequate piping not containing valves which can isolate any vessel may be considered as one unit having an effective working pressure equal to the lowest rated working pressure of any component. All separators shall be equipped with low liquid level shut-in controls. High liquid level shut-in control devices shall be installed when the vessel can discharge to a flare.

(b) All pressure surge tanks shall be equipped with high and low pressure shut-in sensors, a high liquid level shut-in control, flare line, and relief valve.

(c) All atmospheric tanks that may contain possible pollutants, including oil production tanks, surge tanks, etc., shall be equipped with a high liquid level shut-in control. When two or more tanks are connected in series or parallel and the operating levels are equalized, only one high liquid level shut-in control is required, providing it is located so that it cannot be isolated from any tank and will provide adequate high-level protection for all tanks.

(d) All other hydrcarbon-handling pressure vessels shall be equipped with high and low pressure shut-in sensors and relief valves. Vessels connected together by a system of adequate piping not containing valves which can isolate any vessel may be considered as one unit having an effective working pressure equal to the lowest rated working pressure of any component. In addition, such pressure vessels shall be equipped with high and low liquid level shut-in controls.

(e) The following requirements shall apply to all gas-fired production vessels:

i. Fuel supply lines to the main and pilot burners shall be equipped with manually operated shut-off valves.

ii. A flame detector or heat sensor to determine if the pilot is adequate to light the main burner shall be installed; and, on vessels on which the pilot is not continuously lighted, shall indicate a main burner flame failure.

iii. The exhaust stack of natural draft heaters shall be equipped with spark arrestors.

iv. Natural draft air intakes shall be equipped with a flame arrestor.

v. Forced draft burners shall be equipped with a low pressure or low flow rate shut-in sensor.

vi. Vessels in which the media in contact with the fire tubes is not the primary product to be heated shall be protected by high temperature and low level shut-in sensors in the heat exchange media stream..

vii. Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code, July 1, 1974. All relief valves and vents shall be piped in such a way as to minimize the possibility of fluid striking personnel or ignition sources.

viii. Required sensors and monitors will respond to an abnormal condition in

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the vessel by automatically: (1) shutting off fuel supply and (2) shutting off combustible media inflow to the vessel. However, in closed heat-transfer systems where the heated media is temperature degradable and flows through tubes located in the fired chamber, circulation of the media shall continue until the heat exchange area has cooled below the temperature at which the media degrades.

ix. Steam generators shall be equipped with low water levels controls in accordance with applicable provisions of sections I and IV of the ASME Boiler and Pressure Vessel Code, July 1, 1974.

x. An operating procedure shall be posted in a prominent location near the controls of the unit, and personnel responsible for the unit's operation shall be properly trained.

(f) All relief valves shall be set to start relieving at the design working pressure of the vessel and shall be sized to prevent the pressure from rising more than 10 percent above the design working pressure of the vessel or as otherwise provided by section VIII of the ASME Boiler and Pressure Vessel Code, July 1, 1974. The high pressure shut-in sensor shall activate sufficiently below the design working pressure to positively insure operation before the relief valve starts relieving. The low pressure shut-in sensor shall activate no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range.

(g) Pressure sensors may be of the automatic or nonautomatic reset type, but where the automatic reset types are used, a nonautomatic reset relay must be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.

(h) All flare lines shall be equipped with a scrubber with a high level shut-in control.

(i) Surge tanks and all hydrocarbon storage tanks shall be equipped with an automatic fail-close shut-in valve located in the pump suction line as close to the tank as practical. Such valve is to be activated by pump shut-down controls and the platform emergency shutdown system.

(2) *Wellhead and flowline safety devices*. The following safety devices shall be installed and maintained in an operating condition at all times. When wells are disconnected from producing facilities and blindflanged or equipped with a tubing plug, compliance with subparagraphs (a), (b), and (c) below is not required.

(a) All wellhead assemblies shall be equipped with an automatic fail-close surface safety valve installed in the vertical run of the christmas tree.

(b) All flowlines from wells shall be equipped with high and low pressure shut-in sensors located downstream of the well choke. If there is more than 10 feet (3.1 metres) of line between the wellhead wing valve and the primary choke, an additional low pressure shut-in sensor shall be installed in this section. The high pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the line, but in no case shall it exceed 90 percent of the shut-in pressure of the well or the gas lift supply pressure. The low pressure shut-in sensor shall be set no lower than 10 percent or 5 psi (0.34 atm.), whichever is greater, below the lowest operating pressure of the section of the line in which it is installed.

(c) All headers shall be equipped with check valves on the individual flowlines.

(d) The flowline and valve from each well located upstream of and including, the header valves shall be able to withstand the shut-in pressure of that well, unless protected by a relief valve bypass system with connections to rejoin the main production stream at the separator, or at a point upstream of the separator. If there is an inlet valve to a separator, the valve, flowlines, and all equipment upstream of the valve shall also be able to withstand shut-in wellhead pressure, unless protected by a relief valve bypass system with connections to rejoin the main production stream at the separator, or at a point upstream of the separator. In the event a well flows directly to pipeline before separation, the flowline and valves from the well located upstream of, and including the header inlet valve shall be able to withstand the maximum shut-in pressure of the well unless protected by a relief valve connecting to either the platform flare scrubber or some other approved location other than into the departing pipeline.

(e) On all gas lift wells, a check valve shall be installed on the gas input line to the casing.

(f) All pneumatic shut-in systems shall be equipped with fusible material at strategic points.

(g) Remote shut-in controls shall be located on the helicopter deck and on all exit stairway landings, including at least one on each boat landing. These controls shall be quick-opening valves, except that those on the boat landing may be a plastic loop.

(3) *Other equipment*.

(a) All engine exhausts with temperatures greater than 400° F. (205°C.) shall be insulated and piped away from fuel sources. Exhaust piping from diesel engines shall be equipped with spark arrestors.

(b) All pressure or fired vessels used in the production of oil or gas shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, sections, I IV, and VIII, as appropriate, in effect at the time the vessel is installed. Uncoded vessels used shall be hydrostatically tested to a pressure 1.5 times their normal working pressure. The test date, test pressure, and working pressure shall be marked on the vessel in a prominent place. A record of the test shall be maintained by the operator.

(c) A hydrocarbon separator shall be installed in the glycol return line on all glycol dehydration units.

(d) The following requirements shall apply to hydrocarbon gas compressors:

i. Each compressor suction line and associated suction scrubber vessel shall be protected by high and low pressure shut-in sensors, high and low liquid level shut-in controls in the suction scrubber and a pressure relief valve.

ii. Each compressor discharge line shall be protected by a pressure relief valve and high and low pressure shut-in sensors.

iii. Each compressor interstage scrubber shall be protected by high and low pressure and high and low liquid level shut-in controls and a pressure relief valve.

iv. High and low pressure shut-in sensors and low liquid level shut-in controls protecting compressor suction and discharge piping and associated suction and, interstage scrubbers shall be designed to actuate automatic isolation valves located in each compressor suction and fuel gas line so that the compressor unit and associated vessels can be isolated from all input sources. If the compressor unit is installed in a building, the isolation valves shall be located outside the building. Each suction and interstage high liquid level shut-in control shall, as a minimum, be designed to shutdown the compressor prime motor. As an alternative, low liquid level shut-in control(s) installed in suction and interstage scrubber(s) may be designed to actuate automatic shutoff valve(s) installed in the scrubber dump line(s).

v. Each compressor discharge line shall be equipped with a check valve to prevent backflow. If the compressor unit is installed in a building, the check valve shall be located outside the buildings.

vi. Compressor units installed in inadequately ventilated buildings or enclosures shall be protected by a gas detector designed to actuate automatic isolation valves installed in the compressor suction and fuel gas lines.

vii. Automatic isolation valves installed in compressor suction and fuel gas piping shall be actuated by the platform remote manual shut-in system and fire loop, as well as by any abnormal pressure or level condition sensed in the compressor piping or associated scrubber vessels.

viii. Each compressor discharge line shall be equipped with an automatic blowdown valve actuated by the platform fire loop and remote manual shut-in system and by the compressor's gas detection system. The blowdown system must be piped to vent at a nonhazardous location away from all possible sources of ignition.

(e) Motion sensing devices shall be installed on each production platform or structure. This device shall be capable of monitoring platform motion and shall automatically activate the platform shutdown sequence in the event of structural damage or failure.

(4) *Safety device testing*. The safety devices required in paragraphs 2A (1) and (2) above shall be tested by the operator as follows or at more frequent intervals. Records shall be maintained at the field headquarters for a period of one

year, showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation. Such records shall be available to any authorized representative of the Geological Survey.

(a) All pressure relief valves shall be tested for operation annually. Pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. Bench tests not witnessed by Geological Survey personnel must be certified by a third party.

(b) All pressure sensors shall be tested at least once each calendar month, but at no time shall more than six weeks elapse between tests. Any sensor which consistently varies more than ±5 percent from its set pressure shall be repaired or replaced.

(c) All automatic wellhead safety valves and check valves on all flowlines shall be checked for operation and holding pressure once each calendar month, but at no time shall more than six weeks elapse between tests. For any valve which these monthly tests indicate a shorter time interval is needed, such shorter interval shall be instituted. If any wellhead safety valve indicates leakage, it shall be repaired or replaced. A check valve sustaining a liquid flow in excess of 400 cc./min. or gas flow exceeding 15 cubic ft./min. (0.42 cubic metres/min.) shall be repaired or replaced.

(d) All liquid level shut-in controls shall be tested at least once within each calendar month, but at no time shall more than six weeks elapse between tests. These tests shall be conducted by raising or lowering the liquid level across the level control detector.

(e) Automatic inlet shut-off valves actuated by a sensor on a vessel or a compressor shall be tested for operation at least once within each calendar month, but at no time shall more than six weeks elapse between tests.

(f) All automatic shut-off valves located in liquid discharge lines and actuated by vessel low liquid level sensors shall be tested for operation once within each calendar month, but at no time shall more than six weeks elapse between tests.

(5) *Curbs, gutters, and drains.* Curbs, gutters, and drains shall be constructed in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into ocean water.

Sump piles or open-ended sumps shall be used to collect only produced water and liquids from drip pans and deck drains. Closed sumps or sump transfer tanks shall be equipped with a high level shut-in device.

(6) *Fire-fighting system.* A fire-fighting system shall be installed and maintained in an operating condition in accordance with the following:

(a) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in enclosed well bay areas and areas where production-handling equipment is located. A fire-fighting system using chemicals may be used in lieu of a firewater system if determined to provide equivalent fire protection control.

(b) Pumps for the firewater systems shall be inspected and test operated weekly. A record of the tests shall be maintained at the field headquarters for a period of one year. An alternative fuel or power source shall be installed to provide continued pump operation during platform shutdown, unless an alternative fire-fighting system is provided.

(c) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(d) Heat, infra-red or other fire sensing devices shall be installed in all enclosed areas containing wells or production facilities. These devices shall be capable of continuous monitoring for the presence of fire or open flare and shall be used for platform shut-in sequences and the operations of emergency equipment.

(e) A diagram of the fire-fighting system showing the location of all equipment shall be posted in a prominent place on the platform or structure.

(7) *Automatic gas detectors.* An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance with the following:

(a) Gas detection systems shall be installed in all enclosed areas containing production facilities or equipment. Gas detectors shall be installed in all enclosed areas where fuel gas is used; the use of fuel gas odorant is an acceptable alternate.

In partially open buildings, enclosures or meter houses where adequate ventilation is provided in lieu of a gas detector installation, ventilation shall, as a minimum, be by natural draft at a rate not less than one enclosure air change per five minutes.

(b) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located. The gas detector power supply must be from a continually energized power source.

(c) The central control shall be capable of giving an alarm at a point not greater than 25 percent of the lower explosive limit of the gas or vapor being monitored.

(d) A high level setting of not more than 75 percent of the lower explosive limit of the gas or vapor being monitored shall be used for platform shut-in sequences and the operation of emergency equipment.

(e) Records of maintenance and calibration shall be maintained in the field headquarters for a period of one year and made available to any authorized representative of the Geological Survey. The system shall be tested for operation and recalibrated semi-annually.

(f) An application for the installation and maintenance of any gas detection system shall be filed with the Supervisor for approval. The application shall include the following:

i. Type, location, and number of detection heads.

ii. Type and kind of alarm, including emergency equipment to be activated.

iii. Method used for detection of combustible gases.

iv. Method and frequency of calibration.

v. A functional block diagram of the gas detection system, including the electric power supply.

vi. Other pertinent information.

(g) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the platform or structure.

(8) *Electrical equipment.* The following requirements shall be applicable to all electrical equipment and systems installed:

(a) All engines shall be equipped with a low tension ignition system of a low fire hazard-type and shall be designed and maintained to minimize release of sufficient electrical energy to cause ignition of an external combustible mixture.

(b) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500 B in effect at the time of installation are acceptable.

(c) Wiring Methods which conform to the National Electrical Code or IEEE 45 in effect at the time of installation are acceptable.

(d) An auxiliary power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operations in the event of a failure in the primary electrical power supply.

(9) *Erosion.* A program of erosion control shall be in effect for wells having a history of sand production. The erosion control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. A report on the results of the program shall be submitted annually to the Supervisor.

B. *Simultaneous facility operation.* Prior to conducting activities on a facility simultaneously with production operations, which could increase the possibility of undesirable events occurring such as damage to equipment, harm to personnel or the environment, a plan shall be filed and approved by the Supervisor which will provide for the mitigation of such events. Activities requiring a plan are drilling, workover, wireline, and major construction operations. Such plans submitted for approval may cover sequential

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or individual operations. The plan shall include:

1. Description of operations.

2. Schematic plans showing areas of activities.

3. Identification of critical areas of simultaneous activities.

4. Plan for mitigation of potential undesirable events including provisions for coordination and supervision of activities such that all persons involved will be informed as to all activities and be aware of critical areas.

C. *Welding practices and procedures.* The following requirements shall apply to all platforms and structures, including mobile drilling and workover structures. The period of time during which these requirements are considered applicable to mobile drilling structures is the interval from the drilling out of the drive pipe or structural casing until the BOP stack and riser are pulled in the final abandonment, suspension, or completion. These requirements shall apply to workover rigs when such rigs are performing remedial work on any wells open to hydrocarbon bearing zones.

For the purpose of this Order, the term "burning and welding" is defined to include arc or acetylene cutting and arc or acetylene welding.

Each operator shall prepare and submit to the Supervisor for approval a Welding and Burning Safe Practices and Procedures Plan, which includes company qualification standards or requirements for welders. Any person designated as a welding supervisor must be thoroughly familiar with this plan.

Prior to burning or welding operations, the operator shall establish approved welding areas. Such areas shall be constructed or noncombustible or fire resistant materials free of combustible or flammable contents and be suitable segregated from adjacent areas. NFPA Bulletin No. 51B, Cutting and Welding Processes, 1971, shall be used as a guide to designate these areas.

All welding which cannot be done in the approved welding area shall be performed in compliance with the procedures outlined below:

(1) All welding and burning shall be minimized.

(2) Such welding and burning as are necessary on a structure shall adhere to the following practices:

(a) Prior to the commencement of any burning or welding operations on a structure, the operator's designated welding supervisor at the installation shall personally inspect the qualifications of the welders to insure that they are properly qualified in accordance with the approved company qualification standards or requirements for welders. The designated welding supervisor and the welders shall personally inspect the area in which the work is to be performed for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the welding supervisor shall issue a written authorization for the work.

(b) All welding equipment shall be inspected prior to beginning any burning or welding. Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak free and equipped with proper fittings, gauges, and regulators.

(c) During all welding and burning operations, one or more persons as necessary shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual burning or welding operations are in progress.

(d) Prior to any welding or burning, the Fire Watch shall have in his possession firefighting equipment in a condition ready to use.

(e) No welding shall be done on containers, tanks, or other vessels which have contained a flammable substance unless the contents of the vessels have been rendered inert and determined to be safe for welding or burning by the designated welding supervisor.

(f) No welding shall be permitted during wireline operations.

(g) All production shall be shut in at the wellhead while welding or burning in the wellhead or production area.

D. *Requirements for mobile drilling structures.* The requirements of paragraphs 2A(5), 2A(8), and 2C above shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Alaska Area.

RODNEY A. SMITH,
Oil and Gas Supervisor,
Alaska Area.

Approved:
RUSSELL G. WAYLAND,
Chief, Conservation Division.

GULF OF ALASKA

[OCS ORDER NO. 9]

APPROVAL PROCEDURE FOR OIL AND GAS PIPELINES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b).

Section 250.19(b) provides as follows:

(b) The supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of § 250.18 or authorized under any lease issued or maintained under the Act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. *Definition of terms.* As used in this Order, the following terms shall have the meanings indicated:

A. *Pipeline.* Lines installed for the purpose of transporting oil, gas, water, sulphur, or other minerals, including lines sometimes referred to as flow or gathering lines, but excluding lines confined to a platform or structure.

B. *Internal pressure at specified minimum yield strength (IP@SMYS).* Internal Pressure at specified minimum yield strength must be calculated by the use of equations accepted as having an established engineering basis. The Barlow equation, as referenced in Section 841.1 of ANSI Code B 31.8—1969 Gas Transmission and Distribution Piping System, should be used except where the t D ratio exceeds 0.1, in which case the Boardman Formula, as adapted from ANSI Code B 31.3—1968 Petroleum Refinery Piping, should be used for a more accurate representation of actual stress due to internal pressure:

(a) For $t/D=0.1$ $IP@SMYS = \dfrac{2\,St \times E \times T}{D}$

(b) For $t/D=0.1$ $IP@SMYS = \dfrac{2\,St \times E \times T}{D-0.8t}$

S=The specified minimum yield strength of pipe material, in psi.
t=Nominal wall thickness, in inches.
D=Nominal outside diameter, in inches.
E=Longitudinal joint factor obtained from Appendix A.
T=Temperature derating factor:
250°F. or less=1.00
300°F.=.967
350°F.=.933
400°F.=.900.

C. *Maximum allowable pressure (MAP).* The MAP is either 60 percent or 72 percent (dictated by location) of the IP@SMYS. The applicable MAP is the maximum pressure to which a pipeline or segment of pipeline shall be subjected under maximum source pressure conditions. MAP is calculated as follows:

(1) For that portion of the pipeline located on platforms, for pipeline risers, and for submerged pipelines within 300 feet (91.4 metres) of the risers:

$$MAP = 0.60 \times IP@SMYS$$

(2) For submerged pipelines extending beyond 300 feet (91.4 metres) from the riser:

$$MAP = 0.72 \times IP@SMYS$$

D. *Maximum source pressure (MSP).* The maximum pressure to which the pipeline or segment of pipeline could be subjected in the event of a safety system malfunction. For a pipeline receiving production from a separator, (the rated maximum working pressure of the vessel will be considered the maximum pressure that vessel can impress upon the pipeline), pumps, compressors, and other pipelines, the maximum pressure which can be exerted by the source or sources will be considered the MSP. The shut-in tubing pressure of a well producing directly into a pipeline will be considered the MSP of that pipeline. When a pipeline is used to transport production from more than one well, the well with the

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highest shut-in tubing pressure will constitute the MSP.

E. *Maximum operating pressure (MOP)*. The maximum pressure to which the pipeline will be subjected over a period of time under normal operations with fluid flow. The MOP shall not exceed the MAP.

F. *Minimum operating pressure*. The minimum pressure to which the pipeline will be subjected over a period of time under normal operations with fluid flow.

G. *Hydrostatic test pressure (HTP)*. HTP means the required pressure to which a pipeline will be subjected for a specified period of time using water as the testing fluid.

2. *Requirements*. All pipelines shall be designed, installed, maintained and abandoned in accordance with the following:

A. *Safety equipment*. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform or structure, including such pipelines which are not operated or owned by the operator. Operators of platforms or structures shall comply with the requirements of paragraph 2A(1) with regard to required check valves on pipelines departing platforms or structures.

(1) All pipelines boarding a platform or structure shall be equipped with a check valve to prevent backflow. All pipelines departing a platform or structure shall be equipped with a check valve to prevent backflow.

(2) All pipeline pumps and compressors shall be equipped with high and low pressure shut-in sensing devices which when activated will shut-in the pumps or compressors. The low pressure sensor must be located upstream of any check valves. Time delay devices are permissible for low pressure sensors provided the settings are based on continuous chart recordings that demonstrate the variance in pipeline pressures under normal conditions. The chart recordings shall be taken quarterly. The most current of these charts shall be retained in the field office.

(3) All pipelines departing a platform or structure receiving production from the platform or structure and which do not receive production from any boarding pipeline shall be equipped with high and low pressure sensors, located upstream of any check valves on any departing line, to directly or indirectly shut-in the wells on the platform or structure.

(4) All pipelines departing a platform or structure receiving production from a boarding pipeline, and which do not receive production from the platform or structure, shall be equipped with high and low pressure sensors at the departing locale, located upstream of any check valve on the departing pipeline to activate an automatic fail-close valve to be located in the upstream portion of the pipeline boarding the platform or structure. This automatic fail-close valve shall be operated by either the platform or structure automatic and manual emergency shut-in system or by an independent automatic and manual emergency shut-in system.

(5) All pipelines departing a platform or structure receiving production from a boarding pipeline, and which receive production from the platform or structure, shall be equipped with a set of high and low pressure sensors at the departing locale located upstream of any check valve on the departing pipeline and downstream of the junction point of the pipelines. These high and low pressure sensors shall activate an automatic fail-close valve located on the boarding pipeline and directly or indirectly shut-in the wells on the platform or structure. This automatic fail-close valve on the boarding pipeline shall be operated by either the platform or structure automatic and manual emergency shut-in system or by an independent automatic and manual emergency shut-in system.

(6) All pipelines boarding a platform or structure and delivering production to production vessels on the platform or structure shall be equipped with an automatic fail-close valve operated by the shut-in sensing devices of the production vessel and by the manual emergency shut-in system.

(7) All pipelines boarding a platform or structure and delivering production to a departing pipeline that does not receive production from the platform or structure shall be equipped with an automatic fail-close valve operated by high and low sensors on the departing pipeline and a manual emergency shut-in system.

(8) The deletion of safety equipment is allowed on a gas pipeline supplying gas lift to wells on platforms or structures where there is no production equipment, except that a check valve shall be installed in each casing annulus line. The gas lift gas line shall have a check valve and high and low pressure sensors to shut off the gas supply at the source in case of a malfunction.

(9) Where bidirectional gas flow is necessary for gas lift or compressor suction, deletion of check valves on departing or boarding pipelines is allowed provided high and low pressure sensors and an automatic fail-close valve are installed on or near each pipeline riser.

(10) All pressure sensors shall be equipped to permit external testing.

B. *General requirements*.

(1) The size, weight, and grade of all pipe to be installed, including valves, fittings, flanges, bolting, and other required equipment, shall be determined by the anticipated volumes and pressures pursuant to paragraphs 1A, 1B, 1C, 1D, and 2D of this Order. The MAP shall be greater than or equal to the MSP unless the system is protected by an additional independently controlled safety shut-in system. In no case shall MOP exceed the MAP.

(2) All pipelines shall be designed for the protection of the pipeline against water currents, storm scouring, soft bottoms, and other environmental factors.

(3) Pipeline risers installed on the outer portion of platform legs and braces, which could reasonably be exposed to vessel damage by virtue of proximity to normal docking facilities, shall be protected by bumper guards or similar devices.

C. *Corrosion protection*. All pipelines shall be protected against loss of metal due to corrosion using such means as protective coatings and cathodic protection in accordance with the most current National Association of Corrosion Engineers Recommended Practice entitled, "Control of Corrosion of Offshore Steel Pipelines," and as follows:

(1) All pipelines shall be provided with external protective coating capable of minimizing underfilm corrosion. This coating shall have sufficient ductility to resist cracking in required service. All pipe coating shall be inspected on the lay barge prior to installation of the pipe, and any coating damage shall be repaired to maintain overall coating integrity.

(2) All pipelines shall have a cathodic protection system designed to mitigate corrosion. This system will be designed based on a minimum of two percent holidays in the protective coating and a current density of a five milliamperes per square foot (53.7 milliamperes/square metres). The cathodic protection life shall be based on a minimum of 20-year design.

(3) The cathodic protection system of a pipeline protected by sacrificial anodes attached directly to the pipeline shall be designed as if the pipeline were insulated at each end.

(4) A pipeline cathodically protected by a rectifier shall be equipped with a visual, audible, or recorded signal to alarm personnel that the rectifier is not functioning. Electrical measurements and inspections shall be conducted bimonthly to assure the system is operating properly and the conditions affecting the system have not changed.

(5) All pipelines shall be designed to facilitate the installation of internal corrosion monitoring and control devices at both ends of the pipeline where accessible.

(6) All pipelines, with the exception of pipelines transporting production from four or less wells, shall be designed for the installation of pig launchers and receivers. Pipelines transporting production from four or less wells shall be designed for installation of pig traps or be treated with paraffin solvents and corrosion inhibitors to protect the internal integrity of the pipeline.

D. *Hydrostatic testing requirements*. All pipelines shall be designed to allow for hydrostatic testing with water, to at least 1.25 times the MSP. The pipeline shall not be tested with a pressure in excess of 90 percent of the IP of SMYS. The Supervisor may approve a higher test pressure when specially requested and justification is submitted by the operator.

(1) Prior to placing a new pipeline in service, the pipeline shall be hydrostatically tested to at least 1.25 times the MSP for a minimum period of eight hours.

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(2) Prior to returning a pipeline to service after repair of a leak caused by corrosion or rupture due to exceeding the MAP, the pipeline shall be hydrostatically tested to at least 1.25 times the MSP for a minimum period of 24 hours. The Supervisor may approve alternate methods of testing.

(3) Prior to returning a pipeline to service after repair of a leak caused by damage due to foreign objects, storms, manufacturing flaw, or malfunction of a submerged valve, the pipeline shall be hydrostatically tested to at least 1.25 times the MSP for a minimum period of four hours. The Supervisor may approve alternate methods of testing.

(4) Pipelines that have operated for a period of five years or more shall not be operated at a new higher MOP exceeding 1.5 times the former high MOP unless it meets the hydrostatic test requirements for a new pipeline.

(5) A report of all hydrostatic tests conducted shall be submitted to the Supervisor. The report shall include all hydrostatic test data, including procedure, test pressure, hold time, and results.

E. *Installation requirements.* All pipelines shall be designed, installed, and maintained to be compatible with trawling operations and other uses.

(1) All pipelines installed in water depths less than 200 feet (61 metres) shall be buried a minimum of three feet (0.9 metres) below the ocean floor. Alternate methods of pipeline installation may be approved by the Supervisor where unusual conditions dictate such an alternate choice.

(2) Pipelines installed in water depths greater than 200 feet (61 metres) need not be buried unless the Supervisor has determined that the pipeline constitutes a hazard to trawling operations or other uses. In such event, the pipeline shall be buried a minimum of three feet (0.9 metres) below the ocean floor.

F. *Operating requirements.* The operator shall be responsible for the required setting of pressure sensing devices on all oil and gas pipelines connected to a platform, including pipelines which are not operated or owned by the operator.

(1) The high-pressure sensors, required by this Order, shall not be set at a pressure higher than the MAP or 10 percent above the MOP of the pipeline, whichever is less.

(2) The low-pressure sensors, required by this Order, shall not be set at a pressure lower than 30 psig (2 atms.) or 10 percent below the minimum operating pressure of the pipeline, whichever is greater.

(3) These high and low sensor settings and the time interval for any time delay device shall be determined from a pressure recording chart showing the pipeline pressure profile under normal operating conditions over a minimum continuation time span of 24 hours.

G. *Abandonment requirements.* The following procedures shall be used for pipeline abandonment:

(1) Lines shall be flushed and filled with sea water or inerted with nitrogen unless the condition of the pipeline prevents doing so.

(2) Lines shall be cut and closed below the mud line on each end if the line is to be permanently abandoned.

(3) A line to be temporarily abandoned may be either blind flanged or isolated with a closed block valve, in lieu of cutting and capping below the mud line.

(4) Pipelines to be removed shall be flushed with sea water prior to removal.

3. *Pipeline applications.* Pipeline applications shall be submitted in duplicate, to the Supervisor in accordance with the following:

A. *New pipelines.* Applications for the installation of new pipelines shall include:

(1) Plat for plats, with a scale of 1″=2,000′ (1cm=240m), showing the major features and other pertinent data, including water depth, route, location, length, connecting facilities, size, type of products to be transported, and burial depth.

(2) A schematic drawing showing the following:

(a) Pipeline safety equipment and the manner in which the equipment functions.

(b) Sensing devices with associated pressure-control lines.

(c) Automatic fail-close valves.

(d) Check valves.

(e) Vessels.

(f) Manifolds.

(g) The rated working pressure of all valves and fittings.

This schematic drawing or an additional drawing shall also show the placement of corrosion monitoring equipment.

(3) General information including:

(a) Product or products to be transported by the pipeline.

(b) Size, weight, grade, and class of the pipe and risers.

(c) Length in feet (metres) of the line.

(d) Maximum and minimum water depth.

(e) Description of cathodic protection system.

If sacrificial anodes are used on the pipeline or platform or structure, specify the type, size, weight, and spacing of anodes. Provide calculations used in designing the sacrificial anode system, including anticipated life of the line. If a rectifier is to be used, include size of unit or units, voltage and ampere rating and pipelines and platforms or structures to be protected. Provide calculations used in designing the size of unit or units and maximum capacity.

(f) Description of external pipeline coating system and type coating.

(g) Description of internal protective measures including internal coating and provision for corrosion inhibition program.

(h) Specific gravity of the empty pipe.

(i) Anticipated gravity or density of the product or products.

(j) Maximum and minimum operating pressure.

(k) Maximum source pressure.

(l) Maximum allowable pressure. Provide calculations used in determining MAP.

(m) Hydrostatic water test pressure and period of time to which the line will be tested after installation. This test must conform to paragraph 2D of this Order.

(n) Type, size, pressure rating, and location of pumps and prime movers.

(o) Proposed inspection procedures.

(p) Archaeological survey.

(q) Other information as may be required by the Supervisor. (Soil data for route if no pipelines in area.)

B. *Pipeline repairs.* Applications for pipeline repair shall include:

(1) Date and time problem detected. (Example: leak, X-ray of riser indicates wall thickness less than minimum acceptable value, etc.)

(2) Estimated volume of product lost.

(3) Pipeline size and service.

(4) Location of pipeline.

(5) Approximate location of leak and distance from nearest end.

(6) Cause.

(7) Remedial action to be taken.

(8) Proposed hydrostatic pressure test. This test must conform to paragraph 2D of this Order.

C. *Pipeline abandonment.* Applications for pipeline abandonment shall include:

(1) The proposed procedure for compliance with paragraph 2G of this Order.

(2) A location plat describing the pipeline or segment of pipeline to be abandoned in such a manner as to be identifiable for reference purposes.

4. *Operational test and reporting requirements.*—A. *New pipeline completion report.* The pipeline operator shall submit a report to the Supervisor when installation of a pipeline is completed. The report shall include a drawing or plat, with a scale of 1″=2,000′ (1cm=240m), showing the location of the line as installed and the hydrostatic test data required in paragraph 2D.

B. *Pipeline damage report.* Pipeline operators shall immediately report orally to the Supervisor any leak, break, flow restriction or stoppage, or other indicated damage due to the following: corrosion, stuck pig, paraffin, kinking, flattening or nondestructive testing. Proposed methods of repair may be requested and approvals granted orally subject to written confirmation as required in paragraph 3B.

C. *Pipeline repair report.* This report shall be submitted to the Supervisor within a week after completion of the repairs. The report shall include:

(1) Location of pipeline.

(2) Location of leak.

(3) Detailed description of cause.

(4) Detailed description of remedial action.

(5) Hydrostatic test results.

(6) Date returned to service.

D. *Equipment testing.* The high and low pressure sensors and shut-in valves required in paragraph 2A of this Order shall be tested for operation at [illegible] each calendar month but at no [illegible] more than six weeks elapse between

tests. Check valves shall be tested periodically when operationally convenient but at intervals not to exceed a period of one year. Records of these tests shall be maintained at the field headquarters showing the present status and past history of each device including dates and details of inspection, testing, repairing, adjustments, and reinstallation.

E. *Pipeline abandonment report.* The operator shall submit written notification to the Supervisor of the date the abandonment is completed and confirm that the pipeline was abandoned as approved.

F. *Corrosion detection test and report.* All pipelines shall be tested on both ends for the possible existence of internal corrosion. This determination may be by the use of coupons, probes, water analysis (iron count, pH, and scale), or CO_2 (partial pressure) at a minimum of six-month intervals. Lines handling dry hydrocarbons (less than 7 lbs. H_2O/MMcf (0.11 kg H_2O/1,000 cubic metres) for gas and less than one percent BS&W for oil) may be excluded from this requirement. The results and conclusions shall be submitted to the Supervisor during February of each year.

5. *Inspection and reporting requirements.*—A. *Visual inspection.* All pipelines shall be inspected monthly for indication of leakage, using aircraft, floating equipment, or other methods. The results of the inspection will be retained in the company field office for one year.

B. *Hazard damage corrective action report.* If the hazards of storm scouring, soft bottoms, and other environmental factors are observed to be detrimentally affecting the pipeline, the operator shall return the pipeline to an acceptable condition and submit a report of the remedial action taken to the Supervisor.

C. *Pipeline failure investigation.* All pipeline operators shall inspect and analyze every pipeline failure and, where necessary, select samples of the failed section for laboratory examination for the purpose of determining the cause. A comprehensive written report of the information obtained shall be submitted to the Supervisor as soon as available.

D. *Cathodic protection report.* All pipeline cathodic protection facilities shall be inspected and pipe-to-electrolyte potential measurements conducted at a minimum of six-month intervals to assure their proper operation and maintenance. The results and conclusions shall be submitted to the Supervisor during February of each year.

E. *Internal corrosion inspection.*

(1) All pipelines requiring pig launchers and receivers under 2C(6) shall be pigged on a regular basis. These pipelines shall be treated with inhibitors as indicated by the results of corrosion detection tests specified in paragraph 4F. A record of pigging runs and inhibitor treatment shall be submitted to the Supervisor during February of each year.

(2) In the event a pipeline operator elects to run an instrumented pig, the Supervisor shall be notified in ample time to witness the test. The operator shall submit the results and conclusions from the data obtained to the Supervisor within two months after compilation and assimilation.

F. *Riser inspection and reports.* All pipeline risers shall be visually inspected annually for physical and corrosion damage in the splash zone. If damage is observed on protected risers, an inspection using mechanical devices, such as calipers, pit guages, etc., radiographic or ultrasonic inspection shall be conducted. The pipe shall either be inspected to determine the wall thickness and repaired or replaced. All bare risers shall be similarly inspected annually to determine wall thickness and, if necessary, repaired or replaced. The safe operating wall thickness shall be determined by the following formula and the measured thickness compared to the calculated minimum acceptable thickness:

$$t = DP/1.2 \times S \times E \times T$$

Where t = minimum acceptable thickness for the riser to remain in service
D = nominal outside diameter, in inches
P = maximum source pressure, in psi, on the pipeline at time of inspection of the riser
E = longitudinal joint factor obtained from Appendix A
T = temperature derating factor
250° F. = 1.00
300° F. = .967
350° F. = .933
400° F. = .900.
S = the specified minimum yield strength of the pipe material, in psi.

A report of all riser inspections shall be retained in the field office for two years.

If physical or corrosive damage has occurred, necessitating repair or replacement, an application shall be submitted pursuant to paragraphs 4B and 4C.

RODNEY A. SMITH,
Oil and Gas Supervisor,
Alaska Area.

Approved:

RUSSELL G. WAYLAND,
Chief, Conservation Division.

APPENDIX A—LONGITUDINAL JOINT FACTOR E

Specification No.	Pipe class	E factor
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion arc welded	.80
ASTM A 135	Electric resistance welded	1.00
ASTM A 139	Electric fusion welded	.80
ASTM A 155	Electric fusion arc welded	1.00
ASTM A 211	Spiral welded steel pipe	.60
ASTM A 381	Double submerged-arc-welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Furnace butt welded	.60
	Furnace lap-welded [1]	.80
API 5 LX	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
API 5 LS	Electric resistance welded	1.00
	Submerged arc welded	1.00

[1] Manufacture was discontinued and process deleted from API 5 L in 1962.

GULF OF ALASKA

[OCS Order No. 11]

OIL AND GAS PRODUCTION RATES, PREVENTION OF WASTE, AND PROTECTION OF CORRELATIVE RIGHTS

This Order is established pursuant to the authority prescribed in 30 CFR 250.1, 30 CFR 250.11, and in accordance with all other applicable provisions of 30 CFR Part 250, and the notice appearing in the FEDERAL REGISTER, dated December 5, 1970 (35 FR 18559), to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. This Order shall be applicable to all oil and gas wells on Federal leases in the Outer Continental Shelf of the Gulf of Alaska. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). References in this Order to approvals, determinations, and requirements for submittal of information or applications for approval are to those granted, made, or required by the Oil and Gas Supervisor or his delegated representative.

1. *Definition of terms.* As used in this Order, the following terms shall have the meanings indicated:

A. *Waste of oil and gas.* The definition of waste appearing in 30 CFR 250.2(h) shall apply, and includes the failure to

timely initiate enhanced recovery operations where such methods would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. Enhanced recovery operations refers to pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

B. *Correlative rights.* The opportunity afforded each lessee or operator to produce without waste his just and equitable share of oil and gas from a common source of supply.

C. *Maximum efficient rate (MER).* The maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

D. *Maximum production rate (MPR).* The approved maximum daily rate at which oil may be produced from a specified oil well completion or the maximum approved daily rate at which gas may be produced from a specified gas well completion.

E. *Interested party.* The operators and lessees, as defined in 30 CFR 250.2 (f) and (g), of the lease or leases involved in any proceeding initiated under this Order.

F. *Reservoir.* An oil or gas accumulation which is separated from and not in oil or gas communication with any other such accumulation.

G. *Competitive reservoir.* A reservoir as defined herein containing one or more producible or producing well completions on each of two or more leases, or portions thereof, in which the lease or operating interests are not the same.

H. *Property line.* A boundary dividing leases, or portions thereof, in which the lease or operating interest is not the same. The boundaries of Federally approved unit areas shall be considered property lines. The boundaries dividing leased and unleased acreage shall be considered property lines for the purpose of this Order.

I. *Oil reservoir.* A reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

J. *Oil well completion.* A well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

K. *Gas reservoir.* A reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

L. *Gas well completion.* A well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.

M. *Oil reservoir with an associated gas cap.* A reservoir that contains hydrocarbons in both a liquid and a gaseous state (two-phase).

N. *Producible well completion.* A well which is physically capable of production and which is shut in at the wellhead or at the surface, but not necessarily connected to production facilities, and from which the operator plans future production.

2. *Classification of reservoirs.*—A. *Initial classification.* Each producing reservoir shall be classified by the operator, subject to approval by the Supervisor, as an oil reservoir, an oil reservoir with an associated gas cap, or a gas reservoir. The initial classification of each reservoir shall be submitted for approval with the initial submittal of MER data for the reservoir.

B. *Reclassification.* A reservoir may be reclassified by the Supervisor, on his own initiative or upon application of an operator, during its productive life when information becomes available showing that such reclassification is warranted.

3. *Oil and gas production rates.*

A. *Maximum efficient rate (MER).* The operator shall propose a maximum efficient rate (MER) for each producing reservoir based on sound engineering and economic principles. When approved at the proposed or other rate, such rate shall not be exceeded, except as provided in paragraph 4 of this Order.

(1) *Submittal of initial MER.* Within 45 days after the date of first production or such longer period as may be approved, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information.

(2) *Revision of MER.* The operator may request a revision of an MER by submitting the proposed revision to the Supervisor on a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. The Operator shall obtain approval to produce at test rates which exceed an approved MER when such testing is necessary to substantiate an increase in the MER.

(3) *Review of MER.* The MER for each reservoir will be reviewed by the operator annually, or at such other required or approved interval of time. The results of the review, with all current supporting information, shall be submitted on a Request for Reservoir MER (Form 9-1866).

(4) *Effective date of MER.* The effective date of an MER, or revision thereof, will be determined by the Supervisor and shown on a Request for Reservoir MER (Form 9-1866) when the MER is approved. The effective date for an initial MER shall be the first day following the completion of an approved testing period. The effective date for a revised MER shall be the first day following the completion of an approved testing period, or if testing is not conducted, the date the revision is approved.

B. *Maximum production rate (MPR).* The operator shall propose a maximum production rate (MPR) for each producing well completion in a reservoir together with full information on the method used in its determination. When an MPR has been approved for a well completion, that rate shall not be exceeded, except as provided in paragraph 4 of this Order. The MPR shall be based on well tests and any limitations imposed by (1) well tubing, safety, equipment, artificial lift equipment, surface back pressure, and equipment capacity; (2) sand producing problems; (3) producing gas-oil and water-oil ratios; (4) relative structural position of the well with respect to gas-oil or water-oil contacts; (5) position of perforated interval within total production zone; and (6) prudent operating practices. The MPR established for each well completion shall not exceed 110 percent of the rate demonstrated by a well test unless justified by supporting information.

(1) *Submittal of initial MPR.* The operator shall have 30 days from the date of first continuous production within which to conduct a potential test, as specified under subparagraphs 5.B and 6.B of this Order, on all new and reworked well completions. Within 15 days after the date of the potential test, the operator shall submit a proposed MPR for the individual well completion on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), with the results of the potential test on a Well Potential Test Report (Form 9-1868). Extension of the 30-day test period may be granted. The effective date for any approved initial MPR shall be the first day following the test period. During the 30-day period allowed for testing, or any approved extensions thereof, the operator may produce a new or reworked well completion at rates necessary to establish the MPR. The operator shall report the total production obtained during the test period, and approved extensions thereof, on the Well Potential Test Report (Form 9-1868).

(2) *Revision of MPR increase.* If necessary to test a well completion at rates above the approved MPR to determine whether the MPR should be increased, notification of intent to test the well at such higher rates, not to exceed a stated maximum rate during a specified test period, shall be filed with the Supervisor. Such tests may commence on the day following the date of filing notification, unless otherwise ordered by the Supervisor. If an operator determines that the MPR should be increased he shall submit, within 15 days after the specified test period, a proposed increased MPR on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), and any other available data to support the requested revision, including the results of the potential test and the total production obtained during the test period on a Well Potential Test Report (Form 9-1868). Prior to approval of the proposed increased MPR, the operator may produce the well completion at a rate not to exceed the proposed increased MPR of the well. The effective date for any approved increased MPR shall be the first day following the test period. If testing rates or increased MPR rates result in production from the reservoir in excess of the approved MPR, this excess production shall be balanced by underproduction from the reservoir under the provisions of paragraph 4.B of this Order.

(3) *Revision of MPR decrease.* When the quarterly test rate for an oil well completion or the semiannual test rate for a gas well completion required under paragraphs 5.C and 6.C of this Order is less than 90 percent of the existing approved MPR for the well, a new reduced

MPR will be established automatically for that well completion equal to 110 percent of the test rate submitted. The effective date for the new MPR for such well completion shall be the first day of the quarter following the required date of submittal of periodic well-test results under subparagraphs 5.C and 6.C of this Order. Also, the operator may notify the Supervisor on a Request for Well Maximum Production Rate (MPR) (Form 9–1867) of, or the Supervisor may require, a downward revision of a well MPR at any time when the well is no longer capable of producing its approved MPR on a sustained basis. The effective date for such reduced MPR for a well completion shall be the first day of the month following the date of notification.

(4) *Continuation of MPR.* If submittal of the results of a quarterly well test for an oil completion or a semiannual well test for a gas well completion, as provided for in paragraphs 5.C and 6.C of this Order, cannot be timely, continuation of production under the last approved MPR for the well may be authorized, provided an extension of time in which to submit the test results is requested and approved in advance.

(5) *Cancellation of MPR.* When a well completion ceases to produce, is shut in pending workover, or any other condition exists which causes the assigned MPR to be no longer appropriate, the operator shall notify the Supervisor accordingly on a Request for Well Maximum Production Rate (MPR) (Form 9–1867), indicating the date of last production from the well, and the MPR will be canceled. Reporting of temporary shutins by the operator for well maintenance, safety conditions, or other normal operating conditions is not required, except as is necessary for completion of the Monthly Report of Operations (Form 9–152).

C. *MER and MPR relationship.* The withdrawal rate from a reservoir shall not exceed the approved MER and may be produced from any combination of well completions subject to any limitations imposed by the MPR established for each well completion. The rate of production from the reservoir shall not exceed the MER although the summation of individual well MPR's may be greater than the MER.

4. *Balancing of Production.*—A. *Production variances.* Temporary well production rates, resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation of this Order, and such production may be sold or transferred pursuant to paragraph 8 of this Order. However, when normal variations and fluctuations result in production in excess of a reservoir MER, any operator who is overproduced shall balance such production in accordance with subparagraph 4.B below. Such operator shall advise the Supervisor of the amount of such excess production from the reservoir for the month at the same time as Form 9–152 is filed for that month.

B. *Balancing periods.* As of the first day of the month following the month in which this Order becomes effective, all reservoirs shall be considered in balance. Balancing periods for overproduction of a reservoir MER shall end on January 1, April 1, July 1, and October 1 of each year. If a reservoir is produced at a rate in excess of the MER for any month, the operator who is overproduced shall take steps to balance production during the next succeeding month. In any event, all overproduction shall be balanced by the end of the next succeeding quarter following the quarter in which the overproduction occurred. The operator shall notify the Supervisor at the end of the month in which he has balanced the production from an overproduced reservoir.

C. *Shut-in for overproduction.* Any operator in an overproduction status in any reservoir for two successive quarters which has not been brought into balance within the balancing period shall be shut in from that reservoir until the actual production equals that which would have occurred under the approved MER.

D. *Temporary shut-in.* If, as a result of a storm, emergencies, or other conditions peculiar to offshore operations, an operator is forced to curtail or shut in production from a reservoir, the Supervisor may, on request, approve makeup of all or part of this production loss.

5. *Oil Well testing procedures.*

A. *General.* Tests shall be conducted for not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall not begin until after recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation for any purpose. Measured gas volumes shall be adjusted to the standard conditions of 15.025 psia and 60° F. for all tests. When orifice meters are used, a specific gravity shall be obtained or estimated for the gas and a specific gravity correction factor applied to the orifice coefficient. The Supervisor may require a prolonged test or retest of a well completion if such test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Supervisor may approve test periods of less than four hours and pretest stabilization periods of less than six hours for well completions, provided that the test relibility can be demonstrated under such procedures.

B. *Potential test.* Test data to establish or to increase an oil well MPR shall be submitted on a Well Potential Test Report (Form 9–1868). The total production obtained from all tests during the test period shall be reported on such form.

C. *Quarterly test.* Tests shall be conducted on each producing oil well completion quarterly, and test results shall be submitted on a Quarterly Oil Well Test Report (Form 9–1869). Testing periods and submittal dates shall be as follows:

Testing period	Latest date for submittal of test results	For quarter beginning
Sept. 11 to Dec. 10	Dec. 10	Jan. 1.
Dec. 11 to Mar. 10	Mar. 10	Apr. 1.
Mar. 11 to June 10	June 10	July 1.
June 11 to Sept. 10	Sept. 10	Oct. 1.

There shall be a minimum of 45 days between quarterly tests for an oil well completion.

6. *Gas Well testing procedures.*

A. *General.* Testing procedures for gas well completions shall be the same as those specified for oil well completions in subparagraph 5.A except for the initial test which shall be a multi-point back-pressure test as described in paragraph 6.D.

B. *Potential test.* Text data to establish or to increase a gas well MPR shall be submitted on a Well Potential Test Report (Form 9–1868).

C. *Semiannual test.* Tests shall be conducted on each producing gas well completion semiannually, and test results shall be submitted on a Semiannual Gas Well Test Report (Form 9–1870). Testing periods and submittal dates shall be as follows:

Testing period	For submittal of test results	For semi-annual period beginning
June 11 to Dec. 10	Dec. 10	Jan. 1.
Dec. 11 to June 10	June 10	July 1.

There shall be a minimum of 90 days between semiannual tests for a gas well completion.

D. *Back-pressure tests.* A multi-point back-pressure test to determine the theoretical open-flow potential of gas wells shall be conducted within thirty days after connection to a pipeline. If bottomhole pressures are not measured, such pressures shall be calculated from surface pressures using the method or other similar method found in the Interstate Oil Compact Commission (IOCC) Manual of Back-Pressure Testing of gas wells. The results of all backpressure tests conducted by the operator shall be filed with the Supervisor, including all basic data used in determining the test results. The Supervisor may waive this requirement if multi-point back-pressure test information has previously been obtained on a representative number of wells in a reservoir.

7. *Witnessing well tests.* The Supervisor may have a representative witness any potential or periodic well tests on oil and gas well completions. Upon request, an operator shall notify the appropriate District office of the time and date of well tests.

8. *Sale or transfer of production.* Oil and gas produced pursuant to the provisions of this Order, including test production, may be sold to purchasers or transferred as production authorized for disposal hereunder.

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9. *Bottom-hole pressure tests.* Static bottom-hole pressure test shall be conducted annually on sufficient key wells to establish an average reservoir pressure in each producing reservoir unless a different frequency is approved. The Operator may be required to test specific wells. Results of bottom-hole pressure tests shall be submitted within 60 days after the date of the test.

10. *Flaring and venting of gas.* Oil- and gas-well gas shall not be flared or vented, except as provided herein.

A. *Small-volume or short-term flaring or venting.* Oil- and gas-well gas may be flared or vented in small volumes or temporarily without the approval of the Supervisor in the following situations:

(1) *Gas vapors.* When gas vapors are released from storage and other low pressure production vessels if such gas vapors cannot be economically recovered or retained.

(2) *Emergencies.* During temporary emergency situations, such as compressor or other equipment failure, or the relief of abnormal system pressures.

(3) *Well purging and evaluation tests.* During the unloading or cleaning up of a well and during drillstem, producing, or other well evaluation tests not exceeding a period of 24 hours.

B. *Approval for routine or special well tests.* Oil- and gas-well gas may be flared or vented during routine and special well tests, other than those described in paragraph A above, only after approval of the Supervisor.

C. *Gas-well gas.* Except as provided in A and B above, gas-well gas shall not be flared or vented.

D. *Oil-well gas.* Except as provided in A and B above, oil-well gas shall not be flared or vented unless approved by the Supervisor. The Supervisor may approve an application for flaring or venting of oil-well gas for periods not exceeding one year if (1) the operator has initiated positive action which will eliminate flaring or venting, or (2) the operator has submitted an evaluation supported by engineering, geologic, and economic data indicating that rejection of an application to flare or vent the gas will result in an ultimate greater loss of equivalent total energy than could be recovered for beneficial use from the lease if flaring or venting were allowed.

E. *Content of application.* Applications under paragraph D(2) above shall include all appropriate engineering, geologic, and economic data in an evaluation showing that absence of approval to flare or vent the gas will result in premature abandonment of oil and gas production or curtailment of lease development. Applications shall include an estimate of the amount and value of the oil and gas reserves that would not be recovered if the application to flare or vent were rejected and an estimate of the total amount of oil to be recovered and associated gas that would be flared or vented if the application were approved.

11. *Disposition of gas.* The disposition of all gas produced from each lease shall be reported monthly on, or attached to, Form 9-152. The report shall be submitted in the following manner:

	Oil-Well Gas (thousand cubic feet)	Gas-Well Gas (thousand cubic feet)
Sales		
Fuel		
Injected [1]		
Flared		
Vented		
Other (specify)		
Total		

[1] Gas produced from the lease and injected on or off the lease.

12. *Multiple and selective completions.*—A. *Number of Completions.* A well bore may contain any number of producible completions when justified and approved.

B. *Numbering well completions.* Well completions shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir completion, the well completion number shall not change. Appendix A contains a detailed explanation of procedures for naming well completions.

C. *Packer tests.* Multiple and selective completions shall be equipped to isolate the respective producing reservoirs. A packer test or other appropriate reservoir isolation test shall be conducted prior to or immediately after initiating production and annually thereafter on all multiply completed wells. Should the reservoirs in any multiply completed well become intercommunicative the operator shall make repairs and again conduct reservoir isolation tests unless some other operational procedure is approved. The results of all tests shall be submitted on a Packer Test (Form 9-1871) within 30 days after the date of the test.

D. *Selective completions.* Completion equipment may be installed to permit selective reservoir isolation or exposure in a well bore through wireline or other operations. All selective completions shall be designated in accordance with subparagraph 12. B when the application for approval of such completions is filed.

E. *Commingling.* Commingling of production from two or more separate reservoirs within a common well bore may be permitted if it is determined that, collectively, the ultimate recovery will not be decreased. An application to commingle hydrocarbons from multiple reservoirs within a common well bore shall be submitted for approval and shall include all pertinent well information, geologic and reservoir engineering data, and a schematic diagram of well equipment. For all competitive reservoirs, notice of the application shall be sent by the applicant to all other operators of interest in the reservoirs prior to submitting the application to the Supervisor. The application shall specify the well completion number to be used for subsequent reporting purposes.

13. *Gas-cap well completions.* All wells completed in the gas cap of a reservoir which has been classified and approved as an associated oil reservoir shall be shut in until such time as the oil is depleted or the reservoir is reclassified as a gas reservoir; provided, however, that production from such wells may be approved when (1) it can be shown that such gas-cap production would not lead to waste of oil and gas, or (2) when necessary to protect correlative rights unless it can be shown that this production will lead to waste of oil and gas.

14. *Location of wells.*—A. *General.* The location and spacing of all exploratory and development wells shall be in accordance with approved programs and plans required in 30 CFR 250.17 and 250.34. Such location and spacing shall be determined independently for each lease or reservoir in a manner which will locate wells in the optimum structural position for the most effective production of reservoir fluids and to avoid the drilling of unnecessary wells.

B. *Distance from property line.* An operator may drill exploratory or development wells at any location on a lease in accordance with approved plans; provided that no well directionally or vertically drilled and completed after the date of this order in which the completed interval is less than 200 feet (61 metres) from a property line shall be produced unless approved by the Supervisor. For wells drilled as vertical holes, the surface location of the well shall be considered as the location of the completed interval but shall be subject to the provisions of 30 CFR 250.40(b). An operator requesting approval to produce a directionally drilled well in which the completed interval is located closer than 200 feet (61 metres) from a property line, or approval to produce a vertically drilled well with a surface location closer than 200 feet (61 metres) from a property line, shall furnish the Supervisor with letters expressing acceptance or objection from operators of offset properties.

15. *Enhanced oil and gas recovery operations.* Operators shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. A plan for such operations shall be submitted with the results of the annual MER review as required in paragraph 3A(3) of this Order.

16. *Competitive reservoir operations.* Development and production operations in a competitive reservoir may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines, pursuant to 30 CFR 250.50 and delegated authority, that such agreements are practicable and necessary or advisable and in the interest of conservation.

A. *Competitive reservoir determination.* The Supervisor shall notify the operators when he has made a preliminary determination that a reservoir is competitive as defined in this Order. An operator may request at any time that

the Supervisor make a preliminary determination as to whether a reservoir is competitive. The operators, within thirty (30) days of such preliminary notification or such extension of time as approved by the Supervisor, shall advise of their concurrence with such determination, or submit objections with supporting evidence. The Supervisor will make a final determination and notify the operators.

B. *Development and production plans.* When drilling and/or producing operations are conducted in a competitive reservoir, the operators shall submit for approval a plan governing the applicable operations. The plan shall be submitted within ninety (90) days after a determination by the Supervisor that a reservoir is competitive or within such extended period of time as approved by the Supervisor. The plan shall provide for the development and/or production of the reservoir, and may provide for the submittal of supplemental plans for approval by the Supervisor.

(1) *Development plan.* When a competitive reservoir is still being developed or future development is contemplated, a development plan may be required in addition to a production plan. This plan shall include the information required in 30 CFR 250.34. If agreement to a joint development plan cannot be reached by the operators, each shall submit a separate plan and any differences may be resolved in accordance with paragraph 17 of this Order.

(2) *Production plan.* A joint production plan is required for each competitive reservoir. This plan shall include (a) the proposed MER for the reservoir; (b) the proposed MPR for each completion in the reservoir; (c) the percentage allocation of reservoir MER for each lease involved; and

(d) plans for secondary recovery or pressure maintenance operations. If agreement to a joint production plan cannot be reached by the operators, each shall submit a separate plan, and any differences may be resolved in accordance with paragraph 17 of this Order.

C. *Unitization.* The Conservation Manager shall determine when conservation will be best served by unitization of a competitive reservoir, or any reservoir reasonably delineated and determined to be productive, in lieu of a development and/or production plan or when the operators and lessees involved have been unable to voluntarily effect unitization. In such cases, the Conservation Manager may require that development and/or production operations be conducted under an approved unitization plan. Within six (6) months after notification by the Conservation Manager that such a unit plan is required, or within such extended period of time as approved by the Conservation Manager, the lessees and operators shall submit a proposed unit plan for designation of the unit area and approval of the form of agreement pursuant to 30 CFR 250.51.

17. *Conferences, decisions and appeals.* Conferences with interested parties may be held to discuss matters relating to applications and statements of position filed by the parties relating to operations conducted pursuant to this Order. The Supervisor or Conservation Manager may call a conference with one or more, or all, interested parties on his own initiative or at the request of any interested party. All interested parties shall be served with copies of the Supervisor's or Conservation Manager's decisions. Any interested party may appeal decisions of the Supervisor or Conservation Manager pursuant to 30 CFR 250.81. Decisions of the Supervisor or Conservation Manager shall remain in effect and shall not be suspended by reason of any appeal, except as provided in that regulation.

RODNEY A. SMITH,
Oil and Gas Supervisor,
Alaska Area.

Approved.
RUSSELL G. WEYLAND,
Chief, Conservation Division.

APPENDIX A

Subparagraph 12.B *"Numbering Well Completions.* Well completions made under this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir completion, the well completion number shall not change. . . ."

The intent of this Subparagraph is to insure that a completion in a given reservoir and a specific well bore will be assigned a unique name and will retain that name permanently. For further clarification, the following guidelines and examples are offered:

1. Each well bore will have a distinct, permanent number.

2. Each reservoir completion in a well bore will have a unique permanent designation which includes the well bore number in its nomenclature.

3. For the purpose of this Subparagraph, a "completion" is defined as all perforations in a given reservoir in a specific well bore and is not necessarily associated with a tubing string or strings.

4. If more than one completion is made in a well bore, an alphabetical suffix must be used in the nomenclature to differentiate between completions.

5. An alphabetical prefix may be utilized to designate the platform from which the well will be produced.

Example No. 1: The first well drilled from the A Platform is a single completion. Well No. A-1. (Should an operator wish to use an alphabetical suffix with a single completion, he may do so.)

Example No. 2: A well drilled by a mobile rig need not carry an alphabetical prefix. Well No. 1. (If the well is later connected to and produced from a production platform, the well shall be redesignated to reflect an alphabetical prefix.)

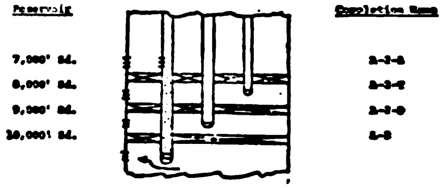
Example No. 3: The second well drilled from the A Platform is a triple completion.

First Completion—A-2.
Second Completion—A-2-D.
Third Completion—A-2-T.

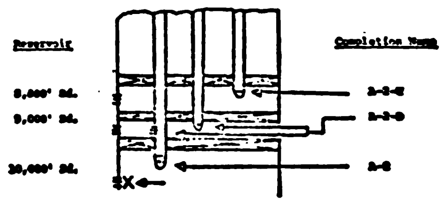
(In the above example, the letters "D" and "T" were used in naming the second and third completions utilizing current industry practice, although the intent is not to restrict operators to the use of these particular alphabetical suffixes. Any alphabetical suffix may be used as long as it is unique to the completion in that reservoir.)

Example No. 4: The drawing is shown to illustrate the fact that once a completion in a specific well bore is designated in a given reservoir, it will retain that name permanently. Let us consider the A-2 completion shown in Example No. 3. Should a recompletion be made in a different reservoir at a later date, it shall be renamed; however, the production from the reservoir associated with the original A-2 completion will always be identified with the A-2 completion. Once the A-2 completion in the 10,000' sand is squeezed and plugged off and the recompletion made to the 7,000' sand, the completion in the 7,000' sand would be designated A-2-A (or some other alphabetical suffix other than the "D" or "T" presently associated with other completions in the 9,000' and 8,000' sands).

The Sundry notice (Form 9-331) submitted to obtain approval for the workover shall be the vehicle for naming the new completion.



Example No. 5: If the A-2 completion in Example No. 4 had been recompleted from the 10,000' sand to the 9,000' sand (where the A-2-D is currently completed), the completion would still be named A-2-D as both tubing strings would be considered one completion for purposes of this Order.



GULF OF ALASKA

[OCS ORDER NO. 12]

PUBLIC INSPECTION OF RECORDS

This order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2. Section 250.97 of 30 CFR provides as follows:

Public inspection of records. Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area.

Section 2.2 of 43 CFR provides in part as follows:

Determination as to availability of records. (a) Section 552 of Title 5, U.S. Code, as amended by Pub. L. 90-23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several

[1] Subsection (b) of section 552 provides that:

(b) This section does not apply to matters that are—

* * * * * *

(Footnote 1 continued on next page.)

categories of records from the general requirement but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office of a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organization unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June, 1967.

(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard.

The operator shall comply with the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Availability of records.* It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area Office, Anchorage, Alaska.

A. *Form 9–152—Monthly report of operations.* All information contained on this form shall be available, except the information required in the Remarks column.

B. *Form 9–330—Well completion or recompletion report and log.*

(1) Prior to commencement of production, all information contained on this form shall be available, except Item 1a, Type of Well; Item 4, Location of Well, At top prod. interval reported below; Item 22, if Multiple Compl., How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production, all information shall be available, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from date of filing Form 9–330 as required in 30 CFR 250.33(b), all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, the lessee or operator shall file a Form 9–330 containing all information requested on the form, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9–330.

C. *Form 9–331—Sundry notices and report on wells*

(1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available, except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available, except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. *Form 9–331C—Application for permit to drill, deepen or plug back.* All information contained on this form, and location plat attached thereto, shall be available, except Item 4, Location of Well, At proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. *Form 9–1869—Quarterly oil well test report.* All information contained on this form shall be available.

F. *Form 9–1870—Semi-annual gas well test report.* All information contained on this form shall be available.

G. *Multi-point back pressure test report.* All information contained on the form used to report the results of required multi-point back pressure test of gas wells shall be available.

H. *Sales of lease production.* Information contained on monthly Geological Survey computer printouts showing sales volumes, value, and royalty of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. *Filing of reports.* All reports on Forms 9–152, 9–330, 9–331, 9–331C, 9–1868, 9–1870, and the forms used to report the results of multi-point back pressure tests, shall be filed in accordance with the following: All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. All items on the form not marked "Public Information" shall be completed in full; and such forms, and all attachments thereto, shall not be available for public inspection. The copy marked "Public Information" shall be completed in full, except that the items described in 1.A, B, C, and D, above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This copy of the form shall be made available for public inspection.

3. *Availability of inspection records.* All accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions are also available for public inspection.

RODNEY A. SMITH,
Oil and Gas Supervisor,
Alaska Area.

Approved:
RUSSELL G. WAYLAND,
Chief, Conservation Division.

[FR Doc.75-5 Filed 1-3-75;8:45 am]

(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential:

* * * * *

(9) Geological and geophysical information and data, including maps, concerning wells.

REVISION OF OCS ORDER NO. 6

Completion of Oil and Gas Wells, Pacific and Gulf of Mexico Areas

On December 11, 1974, notice was given of the intention of the Geological Survey to develop a new Outer Continental Shelf (OCS) Order to provide requirements for oil and gas well completion and workover procedures for the Gulf of Mexico area (39 FR 43234). It is now the intention of the Geological Survey to incorporate such requirements in a revision of existing OCS Order No. 6 for both the Pacific and Gulf of Mexico Areas. These requirements will also be included in the OCS Orders being developed in the Gulf of Alaska and Atlantic OCS areas as appropriate.

Comments are solicited from the general public and interested parties concerning the procedures and operations to be included in the revised Order as shown in the December 11 Notice. Such comments should be forwarded to the Chief, Conservation Division, U.S. Geological Survey, National Center, Mail Stop 650, 12201 Sunrise Valley Drive, Reston, Virginia 22092, on or before March 3, 1975.

W. A. RADLINSKI,
Acting Director.

[FR Doc.75-216 Filed 1-3-75;8:45 am]

Office of the Secretary

[INT FES 74-72]

ANIAKCHAK CALDERA NATIONAL MONUMENT, ALASKA

Availability of Final Environmental Statement

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969, the Department of the Interior has prepared a final environmental statement for the proposed Aniakchak Caldera National Monument in Alaska. The proposal is made in accordance with the Alaska Native Claims Settlement Act of

ATTACHMENT D

UNITED STATES
DEPARTMENT OF THE INTERIOR
Bureau of Land Management

OUTER CONTINENTAL SHELF RESEARCH ADVISORY BOARD

Establishment and Functions

This notice is issued in accordance with the provisions of 5 U.S.C. 552(a)(1), and section 9(a)(2) of the Federal Advisory Committee Act (Public Law 92-463). The Secretary of the Interior has established an Outer Continental Shelf Research Advisory Board after consultation with the Office of Management and Budget, in accordance with the provisions of the Federal Advisory Committee Act (Public Law 92-463). The Office of Management and Budget Committee Management Secretariat has authorized a 7-day period in lieu of the required 30-day period between Federal Register publication of the Board charter, and its filing as prescribed in Section 9(c) of Public Law 92-463. This Board will advise the Assistant Secretary - Land and Water Resources, the Director of the Bureau of Land Management, and other Departmental officers in matters related to environmental baseline and monitoring studies on the Federal Outer Continental Shelf lands. The Board charter is published in its entirety below. Further information regarding this document may be obtained from Mr. Frederick N. Ferguson, Assistant Solicitor - Minerals, Office of the Solicitor, U.S. Department of the Interior, Washington, D.C. 20240, telephone (202) 343-4325.

SIGNED, JOHN C. WHITAKER

Under Secretary of the Interior

Date: MAR 20 1974

CHARTER

OUTER CONTINENTAL SHELF RESEARCH MANAGEMENT ADVISORY BOARD

1. There is hereby established, pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. 1970 ed., Supp. II, App. I), an Outer Continental Shelf Research Management Advisory Board. The Board will advise officers of the Department in the performance of discretionary functions of the Department under the Outer Continental Shelf Lands Act (43 U.S.C. §§ 1331-1343) in connection with baseline environmental data gathering and environmental monitoring on the Outer Continental Shelf (OCS). The functions of the Board are solely advisory.

2. The objective of the Board is to advise the Assistant Secretary-Land and Water Resources, the Director, Bureau of Land Management (BLM) and other officers of the Department, in the design and implementation of environmental research projects related to oil and gas exploration and development on the OCS. The objectives of the OCS program are: (1) orderly resource development, (2) protection of the environment, and (3) receipt of fair market value. This Board through it's advisory efforts will assist the Bureau in meeting objectives (1) and (2). In order to fully realize its potential, it is anticipated that the Board will be required for the duration of OCS environmental baseline research and monitoring studies, a period of approximately ten years. The Board will, however, terminate on December 31, 1975, unless prior

to that date it is renewed for an additional period by the Secretary of the Interior, acting within his discretion and in accordance with the provisions of section 14(a)(2) of the Federal Advisory Committee Act, supra.

3. The Board will report directly to the Assistant Secretary-Land and Water Resources. (a) The Assistant Secretary-Land and Water Resources shall, after consultation with the Assistant Secretary-Energy and Minerals and the Assistant Secretary for Fish, Wildlife and Parks, appoint an employee of the Department of the Interior as Chairman for the Board. The Assistant Secretary-Land and Water Resources shall be responsible for assuring that the Board operates within statutory and Departmental requirements for the management of advisory committees. The Director, BLM, shall provide administrative support. (b) Each of the following Departmental bureaus shall appoint one member to the Board: the Geological Survey, and the Bureau of Sport Fisheries and Wildlife. The Administrator of the Environmental Protection Agency and the Administrator of the National Oceanic and Atmospheric Administration may each appoint one member. (c) At the invitation of the Secretary of the Interior, the Governor of each State off the coast of which OCS research projects are scheduled may nominate for appointment by the Secretary one member who shall represent that State on the Board. Initially the Governors of Mississippi, Alabama, and Florida will be asked to nominate Board

members. As OCS research projects expand into other geographic areas the Governors of the respective States involved may be invited to nominate members for appointment to the Board. (d) Each Federal member shall serve until his resignation, the termination of the Board, or his removal by the officer appointing him. If the agency appointing a member removes that member, it may appoint another in his place. Each non-Federal member shall be appointed to serve a one-year term, but may be re-appointed for additional one-year periods if the OCS area seaward of his State is still under active research.

4. (a) Subject to the limitations imposed by this Charter, the Board may establish its own procedures for the conduct of business. To facilitate the performance of the Board's functions, the Chairman may establish committees composed of members of the Board. Most scheduled meetings will be of specific committees, but the Chairman will have the latitude to invite any individual State member to any committee meeting. (b) The Board shall prepare an annual report to the Secretary on the status of ongoing environmental OCS research. This report will be made available to the public.

5. The Chief Scientist for the BLM OCS environmental research program or a person designated by him will attend all Board and committee meetings and will assist the Chairman wherever possible.

6. The Board will meet at the call of the Chairman, who shall give at least fifteen day's notice in writing. The Board is expected to meet at least bi-annually. Meetings will be conducted in accordance with statutory and Departmental requirements for advisory committees as prescribed in 308 DM 2 of the Department of the Interior Manual. The estimated total annual operating costs of the Board are $10,000 and one man year of staff support.

7. The formation of this committee is determined to be in the public interest in connection with the performance of duties of this Department pursuant to statute as stated in paragraph 1 above. This Charter shall become effective April 1, 1974.

SIGNED, JOHN C. WHITAKER

Under Secretary of the Interior

Date: MAR 20 1974

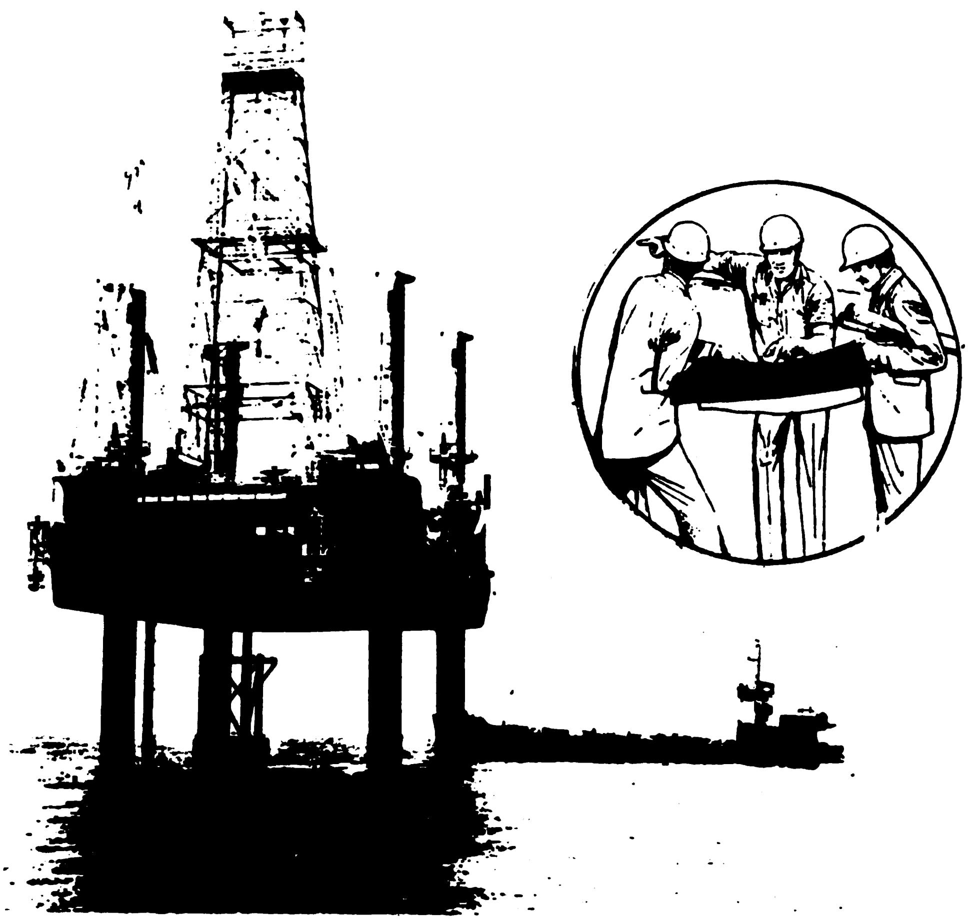
ATTACHMENT E

SUPPLEMENT NO. 1

TO THE

REPORT OF THE WORK GROUP ON OCS SAFETY & POLLUTION CONTROL, MAY 1973

U.S. GEOLOGICAL SURVEY



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MAY 1974

Supplement No. 1

to

REPORT OF THE WORK GROUP ON OCS SAFETY AND POLLUTION CONTROL, MAY 1973

U. S. Geological Survey

Work Group Members:

A. Dewey Acuff
J. R. Balsley
Henry W. Coulter
B. F. Grossling
Hubert Risser
W. A. Radlinski, Chairman

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May 1974

CONTENTS

Foreword

This supplement is a response to recommendations of the report, Energy Under the Oceans, a technology assessment of Outer Continental Shelf oil and gas operations, published in November 1973, by the University of Oklahoma Press. The report is the result of a study conducted by an interdisciplinary research team, headed by Dr. Don E. Kash and Dr. Irvin L. White, University of Oklahoma, and funded by the National Science Foundation.

Responses are made to only those recommendations which pertain to safety and pollution control and over which the U. S. Geological Survey has some control or responsibility. The Work Group which prepared this supplement consisted of the same members who prepared the May, 1973, report responding to recommendations of three earlier studies conducted at the request of the Survey--one by a team of NASA Specialists, one by a group of USGS Systems Analysts, and one by a panel of the Marine Board, National Academy of Engineering.

The Chairman reviewed the University of Oklahoma report at an NSF critique on September 7, 1973, and at an NSF-RANN Symposium on November 19, 1973. The latter review is included as an appendix.

RESPONSE TO RECOMMENDATIONS OF "ENERGY UNDER THE OCEANS"

(A Supplement to the May 1973 Report of the Work Group on OCS Safety and Pollution Control)

U. S. Geological Survey

The report, Energy Under the Oceans,[1/] contains 39 recommendations concerning oil and gas operations on the Outer Continental Shelf. In responding to these recommendations, the U. S. Geological Survey Work Group on OCS Safety and Pollution Control placed them in four categories as follows:

I. Recommendations Over Which the USGS Has No Control

II. Recommendations Already Implemented or in Progress

III. Recommendations Calling for Modifications of Earlier Responses

IV. New Recommendations

I. RECOMMENDATIONS OVER WHICH THE USGS HAS NO CONTROL

This category includes OU[2/] recommendations which the USGS cannot implement because of lack of authority or responsibility, or which are specifically addressed to other organizations. No response is made to these by the Work Group. There are 25 recommendations in this category--Nos. 1-7, 9-16, 20, 21, 23-26, 29, 34, 36, and 37. Additionally, OU Recommendation No. 8 calls for a continuation of the present separation of functions and responsibilities between USGS and BLM and, therefore, requires no response from the Work Group. It further recommends a comprehensive plan for OCS development, but the increments of the plan are covered in the other OU recommendations and the applicable ones are addressed individually below.

1/ A Technology Assessment of Outer Continental Shelf Oil and Gas Operations prepared by an interdisciplinary research team under the aegis of the Science and Public Policy Program at the University of Oklahoma, 1973, funded by the National Science Foundation.

2/ OU--University of Oklahoma

II. RECOMMENDATIONS ALREADY IMPLEMENTED OR IN PROGRESS

In the second category of OU recommendations are four (Nos. 27, 28, 30, and 35) that are nearly identical to recommendations made in earlier studies. The Work Group has already responded to these in its report of May, 1973, and implementation actions are in progress. Included are:

OU 27. *Standards. USGS should establish equipment requirements in terms of the objectives to be achieved. While these requirements should include detailed performance standards for all pieces of equipment affecting safety and environment, design specifications should not be allowed to act as a deterrent to technological development. The presently used fines and orders for suspension of operations are generally adequate. Detailed standards will require equipment suppliers to establish quality-control procedures. (Chapter VI)*

- Agree. See Work Group Recomendation No. 5 (May 1973 report).

The first project undertaken by an API Committee formed in response to this recommendation was the development of a recommended practice for design, installation, and operation of subsurface safety valve systems (API RP 14B), and specifications for subsurface safety valves (API Std. 14A). These have now been published. A facility for testing of subsurface safety valves is being constructed in Houston, Texas, and will be operated by an independent research institute. A committee is being formed to conduct quality assurance inspections of subsurface safety valve manufacturers. The manufacturers must comply with the quality assurance program as set forth in the specifications for subsurface safety valves in order to be able to use the API monogram on their valves.

Additional projects undertaken by the Committee include: recommended practice for the design, installation, and operation of offshore platform basic surface safety systems (draft standards have been issued); specifications for surface safety valves and actuators; and a recommended practice for platform piping system design. As in the case with subsurface safety valves, quality assurance programs for other equipment items will be initiated as appropriate.

The American Petroleum Institute, the American Society for Testing Materials, the American Society of Mechanical

Engineers, the National Association of Corrosion Engineers, and other similar organizations, as appropriate, will be requested to develop needed standards. USGS representatives will participate in these efforts. Standards developed by these organizations, and appropriate existing standards now referenced in OCS orders, will be submitted to the American National Standards Institute (ANSI) for development, also with USGS participation, and for ANSI approval as national voluntary consensus standards.

OU 28. *Failure Reporting. USGS should establish improved reporting and systematic analysis procedures for failures, malfunctions, and equipment defects, as well as issue appropriate notices and warnings.*

- Agree. See Work Group Recommendations Nos. 1, 2, and 3 (May 1973 report).

  The USGS is in the process of developing a Failure Reporting and Corrective Action System with a target completion date of June 1974. A "Safety Alert" system for immediate notification of all operators of failures and accidents was established in September 1972.

OU 30. *Review Technology. USGS should appoint an independent and representative committee of experts to review state-of-the-art in OCS technologies periodically and recommend desirable changes in equipment and performance standards. (Chapter VI)*

- Agree. See Work Group Recommendation No. 15 (May 1973 report). Such a committee was established in July 1973, under the aegis of the Marine Board of the National Academy of Engineering. Its emphasis is on technologies related to safety and pollution control.

OU 35. *Industry Cooperation. USGS should actively promote greater industry cooperation in the development of safety, accident prevention, and environmental protection technologies. Industry should be assured that cooperation in these designated areas will not be subject to anti-trust action. This could be accomplished by having the Anti-Trust Division of the Department of Justice issue guidelines for cooperative efforts or by having the Division give opinions on specific proposals. (Chapter VI)*

- Agree. See Work Group Recommendations Nos. 4, 5, and 10 (May 1973 report). Three cooperative committees with

API were established in September 1972--Offshore Safety and Anti-Pollution Equipment Standards; Offshore Safety and Anti-Pollution Research; and offshore Safety and Anti-Pollution Training and Motivation. All are active. The Department of Justice, by letter of November 29, 1972, stated that "it would not violate the antitrust laws for the Geological Survey to disseminate lessee-filed reports relating to the breakdown of safety and anti-pollution control equipment to all lessees operating on the OCS."

III. RECOMMENDATIONS CALLING FOR MODIFICATIONS OF EARLIER RESPONSES

In the third category of OU recommendations are six (Nos. 18, 19, 31, 32, 33, and 39) that are similar to recommendations already made by the Work Group but call for some additional responses. The Work Group's responses to these are as follows:

OU 18. *<u>OCS Orders: Coverage</u>. All design specifications and regulations for which USGS has administrative responsibility, including those resulting from interagency agreements, should be detailed in OCS orders for each USGS area. OCS orders should be a detailed composite of the regulations and criteria under which oil and gas operations are to be carried out. Such a composite would inform both industry and the interested public of operational standards. (Chapter VI)*

OU 19. *<u>OCS Orders: Preparation</u>. All OCS orders should be reviewed in advance by committees representing both industry and other interested parties selected by the Chief of the Conservation Division of USGS. At present, preparation of OCS orders involves industry participation. For example, in the Gulf Coast area, proposed orders are reviewed by the Offshore Operators Committee. Broadening the range of reviewers should assure sensitivity to a wide set of social concerns at the immediate management level. Placing selection in the Conservation Division in Washington should provide access to the best informed people in organizations such as the national environmental interest groups. (Chapter VI)*

- With respect to the OU Recommendation No. 18, the Work Group agreed with and responded to all aspects, except it did not specifically address the matter of interagency agreements. It does so in the revised recommendation given below (paragraph d.).

With respect to OU Recommendation No. 19, the Work Group agrees that broadening the range of reviewers is desirable, and further concludes that proposed Orders should be made available to all interested organizations on an equal basis. It may be necessary during the drafting stage to consult with individuals, from industry or elsewhere, on specific aspects of proposed Orders in their capacity as individual experts on certain specialized requirements. Proposed Orders, however, should not be made available to industry or other groups prior to their publication in the Federal Register.

Accordingly, Work Group Recommendation No. 13 (May 1973 report) is revised as follows to respond to OU Recommendations 18 and 19 (additions and changes are underlined):

WORK GROUP RECOMMENDATION NO. 13 (Revised)

a. Formalized procedures of the type outlined in the NASA recommendation should be established for development and revision of OCS Orders.

b. In general, OCS Orders should specify the objectives to be achieved, with standards for achievement included by reference.

c. The Work Group agrees with the NAE recommendations that 1) there should be continuation and refinement of the current practice of requiring submission of plans of applicants in terms of equipment and including personnel qualifications and training procedures; and 2) that regulations should take into account on a continuing basis the results of the analysis of information resulting from accident evaluation, as well as consideration of natural environmental hazards.

d. All memoranda of understanding and interagency agreements concerning management of OCS petroleum activities should be made available in a single document, and appropriate references made in OCS Orders.

e. The Conservation Division should adopt the following procedures for the development of new and revised OCS Orders:

   (1) Announce in the Federal Register its intention to prepare a new or revised Order and solicit comments and recommendations.

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(2) Prepare a draft of the Order and publish it in the Federal Register for comment.

Steps (1) and (2) may in some cases be concurrent.

(3) After receipt of comments, Division personnel may meet with interested organizations or consult with individual experts on the various requirements of the Order.

(4) Revise the draft Order, if appropriate, to take into account the information developed from steps (2) and (3).

(5) If the revision is extensive or significant, republish the Order in the Federal Register as a redraft for further comment. Otherwise, publish it in the Federal Register as a final Order with an effective date.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should prepare written procedures outlining the step-by-step actions to be followed in the formulation of OCS Orders for all areas and should assemble and make available all applicable memoranda of understanding and interagency agreements.

OU 31. *Government R&D.* *USGS should undertake an expanded research, development, and testing program as necessary to insure optimal regulation and rapid development of new equipment and procedures. So far as possible, this work should be contracted with organizations outside the R&D system of the petroleum industry. This will help to insure that USGS and OCS operators maintain continuing effective communications with other technological communities. (Chapter VI)*

OU 39. *Inadequate Components.* *USGS should immediately compile a list similar to the following one* (given on pages 259 and 260 of the OU report), *and each year publish a summary review of the progress achieved in correcting weaknesses. This review should continue until the indentification system previously recommended is operational. The physical technologies with weaknesses fall into three categories: need to be developed, need to be improved, and need to be deployed. (Chapter VI)*

- Concerning R&D, the thrust of the Work Group's Recommendation No. 4 (May 1973 report) was to encourage industry to conduct the necessary R&D because of its operational responsibility for safety and pollution prevention. Accordingly, the approach was to establish an API-USGS R&D Committee to encourage industry in this activity. A list of pertinent R&D projects in progress is being completed together with a list of those needs that require new or improved development. Nevertheless, the USGS should have capability for R&D development. Therefore, the Work Group further recommended that in those cases where industry does not respond to R&D needs, the USGS will contract for the required work.

  The Work Group agrees with the second part of OU's Recommendation No. 31--to contract for R&D with organizations outside the petroleum industry to insure effective communications with other technological communities--and responds to this proposal in its revised Recommendation No. 4 given below.

  With respect to OU's Recommendation No. 39, implementation of the Work Group Recommendations Nos. 1, 2c, 3, 4, and 6 (May 1973 report) will provide a basis for compiling a list of inadequate components as well as promotion of R&D for corrective actions. The Work Group did not in its earlier recommendations address the desirability of publishing an annual summary review of progress being made towards correcting the weaknesses. It agrees, however, that this should be done.

  Accordingly, to respond to OU's Recommendations Nos. 31 and 39 the Work Group revises its Recommendation No. 4 (May 1973 report) as follows (additions and changes are underlined):

  WORK GROUP RECOMMENDATION NO. 4 (<u>Revised</u>)

  a. The USGS, in cooperation with the API <u>or other appropriate organizations</u>, should establish a program to encourage and promote research and development in safety and anti-pollution equipment and systems. Current and completed research and development should be taken into account in the determination of specific needs. Such needs should be communicated to industry

through API or other appropriate organizations, and issued by USGS as an annual summary report. For those needs where there is no response from industry, or the response is unsatisfactory, the USGS should contract for the required work, utilizing, when appropriate, organizations outside the usual petroleum industry R&D establishments to perform such research. (See also Recommendation No. 8a.)

b. With specific reference to the NAE recommendations, the Work Group recommends:

(1) The promotion of industry consensus standards should be effected through a cooperative arrangement with API (see Work Group Recommendation No. 5).

(2) Requests should be made to NOAA, USCG, and EPA to sponsor programs to study the effects of various amounts of crude oil intrusion into the marine environment, taking into account site variables.

(3) The recommendation to undertake quantitative studies of the effectiveness of methods for cleaning up oil from the marine environment should be referred to the U. S. Coast Guard.

(4) The development and testing of damage-limiting and fail-safe systems in the area of damage control, fire-fighting, and well control should be an item for follow-up under cooperative arrangements with API, or other appropriate organizations.

c. Industry should be encouraged to grant reasonable access to patented safety and pollution control devices and systems to offshore operators.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should identify those physical technologies and operational

methods in need of R&D, which have a significant impact on safety and pollution control, and for which industry R&D efforts are considered inadequate or lacking. As these are identified, the Division should prepare a plan for contracting with organizations outside the petroleum industry, but giving consideration to R&D work which could be carried out by the Government itself. The plan should include recommendations for the funding of such R&D work.

The Conservation Division should also establish which organizations, other than API, could be considered for assistance in the R&D efforts of the USGS, and their participation utilized when appropriate.

OU 32. *Personnel Standards. USGS should develop uniform standards and certification requirements for personnel who perform inspection and test functions. (Chapter VI)*

OU 33. *Personnel Training. USGS should develop a program to establish improved and standardized training and procedures for operating personnel. This program should utilize the expertise of organizations and individuals such as behavioral scientists who specialize in training. (Chapter VI)*

- Work Group Recommendation No. 9 (May 1973 report) does not preclude the development of standards and requirements for personnel who perform inspection and test functions. However, Recommendation No. 9 should be amended to identify this specific need. Likewise, the desirability of utilizing training specialists should be addressed. Accordingly, Work Group Recommendation No. 9 (May 1973 report) is changed as follows (additions and changes are underlined):

WORK GROUP RECOMMENDATION NO. 9 (Revised)

a. The USGS, working with industry through API, should set standards and requirements for training of personnel, to include, but not be limited to, the following:

   (1) A requirement that all operator or third party personnel, who perform

inspection and test functions related to safety and pollution control, be formally trained and qualified.

(2) A requirement for minimum training in safety and pollution prevention and control for all company and contractor personnel, including identification and proper use of safety equipment, emergency procedures, and first aid.

(3) A requirement that appropriate company and contractor field personnel be briefed on USGS regulations and orders.

b. Standards and requirements for such training should be specified in OCS Orders and a certification, by the operator, of compliance should become a prerequisite for inspecting, testing, and for certain permits and operational work. A system for updating and auditing such training should be developed. Appropriate credit should be given for pertinent experience.

c. The expertise of organizations and individuals who specialize in training should be utilized in the development of standards and requirements for training.

d. USGS field supervisory and inspection personnel should be required to participate in training courses appropriate to their responsibilities.

(The "third party" inspectors referred to in a.(1) above could be someone in the employ of the operator who is not responsible for the operations he is inspecting and who reports directly to management, or someone who is an employee of an outside firm with which the operator or group of operators contract for inspection services.)

IMPLEMENTATION ACTION REQUIRED

Arrangements have been made with API for a joint effort to develop the necessary standards and specifications for training of industry personnel. The Conservation Division should pursue this effort and revise OCS Orders accordingly.

Requirements for appropriate training of USGS personnel should be included in the Division Manual.

The Conservation Division should arrange for briefing programs on USGS regulations and orders.

IV. NEW RECOMMENDATIONS

The final category of OU recommendations include three (Nos. 17, 22, and 38) that are essentially different from those considered by the Work Group. These are discussed in the text that follows.

OU 17. *USGS Management. With limited exceptions, post-lease sale management of OCS oil and gas operations should be concentrated in USGS. The objective of this concentration of management is to eliminate gaps and overlaps and establish clear-cut responsibility. Such concentration will also assure that management decisions conform to the development plan laid out in the hierachy of impact statements. Any impact statements triggered by post-lease sale activities should be the responsibility of USGS and be subsidiary to the lease sale statement. Where necessary, transfer of operational responsibility to USGS should be accomplished by inter-agency agreements. In summary, then, the USGS should continue to administer all of its present post-lease activities plus the following: (Chapter IX)*

- The Work Group agrees that the USGS should continue to administer all of its present post-lease activities. Comments on OU Recommendations 17a. through 17d. follow.

OU 17a. *OSHA. By agreement between Labor and Interior, OCS responsibilities assigned to the Department of Labor by the Occupational Safety and Health Act (OSHA) should be administered by USGS. The standards themselves should be developed by Labor with the advice of USGS and the Department of Health, Education, and Welfare (HEW). Such an arrangement will increase the effective day-to-day administration of the OSHA standards since USGS is already equipped to inspect OCS facilities. Further, these safety*

and health concerns are intimately tied to equipment design and operational procedures that are already a USGS responsibility. As a final advantage, this approach relieves industry of an additional layer of inspectors.

- The Work Group agrees. A draft of a Memorandum of Understanding was completed in March 1974 but questions of statutory authority and responsibility are as yet unresolved.

WORK GROUP RECOMMENDATION NO. 16

A Memorandum of Understanding between the USGS and OSHA should continue to be sought.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should continue to take the lead in negotiating a Memorandum of Understanding between OSHA and the USGS.

OU 17b. *Environmental Administration. USGS should be responsible for enforcing all environmental quality standards applicable to OCS oil and gas operations. Where necessary, agency responsibilities should be clearly defined in inter-agency agreements between Interior, Transportation, and EPA.*

- Enforcement authorities are usually assigned by statutes. However, various inspection and monitoring activities upon which enforcement actions are based can sometimes be shared or delegated. Accordingly, current efforts towards finalizing various Memoranda of Understanding to clearly define the respective functions, scope of activities and responsibilities among the agencies involved in various aspects of environmental protection on the OCS should be expedited, and the results publicized for the guidance of all concerned. The Work Group addresses specific items in this regard in its Recommendations Nos. 13 (Revised), 16, and 17 of this report.

OU 17c. *Rights-of-Way. By formal agreement between BLM and USGS, BLM should issue rights-of-way for common carrier pipelines only upon recommendation of the USGS. This will assure that coordination exists between common carrier lines and the gathering lines presently regulated by USGS. Such authority will allow USGS to insure that pipeline development conforms to the plans developed in the impact statements. Present responsibility for pipelines is fragmented, and some agencies are incapable of meeting their regulatory responsibilities.*

OU 17d. *Pipelines. By formal agreement between the Office of Pipeline Safety (OPS) and Interior, USGS should be designated as responsible for enforcing design and performance standards for offshore pipelines which are now under OPS jurisdiction. The standards, however, should be jointly formulated by OPS and USGS. USGS presently exercises such authority over gathering lines.*

- **Activities for the development of Memoranda of Understanding between USGS, BLM, and OPS in accordance with the intent of OU Recommendations 17c. and d. have been underway for some time. The principal delaying factors have been the need for reviews of the respective pipeline administering activities, including legal reviews, to clarify the statutory authorities and responsibilities of USGS, BLM, and OPS.**

  Current draft proposals of Memoranda of Understanding between USGS and BLM provide for USGS review, prior to final action by BLM, of all rights-of-way applications to install common carrier type pipelines pursuant to 43 CFR 2883. The reviews by USGS would focus on the technical aspects of OCS pipeline design, installation, maintenance and operation in accordance with appropriate regulations and standards designed for safety and environmental protection, and to avoid undue interference with other uses of the OCS and its superjacent waters. The USGS, in cooperation with BLM, will continue efforts to formulate an agreement with OPS whereby OPS safety standards developed for OCS pipelines may be enforced by the USGS.

WORK GROUP RECOMMENDATION NO. 17

a. A Memorandum of Understanding between USGS nad BLM should be developed whereby BLM approval of pipeline rights-of-way applications will require a determination by USGS of the adequacy of the application with respect to design, installation, maintenance and operation.

b. A Memorandum of Understanding between USGS, BLM, and OPS should be formulated whereby the USGS will enforce OPS safety standards, jointly developed by OPS and USGS, for OCS pipelines.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should continue efforts to formulate a Memorandum of Understanding between the USGS and BLM concerning pipeline rights-of-way and a Memorandum of Understanding between USGS, BLM, and OPS for the enforcement of safety standards for pipelines.

OU 17e. *Gas Reserves. By formal agreement between the Federal Power Commission (FPC) and Interior, USGS should be required to provide estimates of recoverable gas reserves to be served by proposed new gas lines. Attached to the estimates should be an assessment of how the line will fit into the development plan established in the impact statements. Additionally, USGS should be available to FPC for consultation on all questions concerning lines. The purpose is to assist FPC in approving new pipelines so that they conform to the development plan established in the impact statements.*

- Estimates of recoverable gas reserves to be served by proposed new gas lines are the responsibility of FPC, but the USGS has cooperated with the FPC when requested and is available for assistance and consultation.

OU 22. *Apply FWPCA to OCS. The FWPCA Amendments of 1972 should be amended specifically to apply discharge provisions to the OCS. Under this arrangement,*

EPA would establish the standards, but as recommended earlier, USGS would have enforcement responsibility. There is no apparent reason why the general principle of a separate agency to set environmental standards should not be applicable to the OCS. Such a separation provides an additional check and increased public credibility in this sensitive area. (Chapter X)

- The OU recommendation implies that the pollutant discharge provisions of the Federal Water Pollution Control Act (FWPCA) Amendments of 1972 are not applicable to OCS lease operations. This is contrary to the memorandum opinion of January 30, 1973, of the Assistant Solicitor, International Marine Minerals, Department of the Interior. The Assistant Solicitor's opinion was that discharges of pollutants from OCS structures are subject to the National Pollutant Discharge System established by the 1972 FWPCA Amendments. The applicable paragraph of the opinion states:

  > "It should be noted that the Administrator, Environmental Protection Agency, is given broad discretionary and regulatory authority in implementing and administering the provisions of this legislation. In particular, your attention is invited to section 501(b) authorizing the Administrator to utilize the officers and employees of any other agency of the United States (with the consent of the head of such agency) to assist in carrying out the purposes of the Act. In these circumstances, it is recommended that you contact appropriate EPA officials regarding the possibility of an agreement under which the expertise of Geological Survey officials would be utilized in the administration of the National Pollutant Discharge System in its application to discharges arising from OCS lease operations."

  Accordingly, the USGS has initiated discussions with EPA to consider the feasibility of a Memorandum of Understanding to minimize a redundancy of efforts and to utilize the expertise of USGS field personnel in the administration of the National Pollutant Discharge System with respect to OCS lease operations.

- o The USGS and EPA should continue to pursue their discussions leading to the joint development of discharge standards for the OCS and a Memorandum of Understanding calling for enforcement by the USGS.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should pursue efforts to develop a Memorandum of Understanding between USGS and EPA for the formulation and enforcement of pollutant discharge standards.

OU 38. *Subsea Production Systems. USGS should encourage early development and use of subsea production systems. Parallel to this, efforts should be made to formulate those specifications and regulations necessary to insure safe operation of subsea production systems. (Chapter VI)*

- o Subsea production systems represent one of many relatively new and advanced systems and technologies presently under development and in limited use which, of course, should be encouraged. USGS solicits briefings and demonstrations by the developers of such systems, and provides advice on requirements and design features. Specifications and regulations necessary to insure safe operations of subsea production systems can be formulated by implementation of Work Group Recommendations Nos. 5, 6, and 13 (May 1973 report).

WORK GROUP RECOMMENDATION NO. 19

a. The USGS should make a special effort to become acquainted with all subsea production systems under development and in use.

b. Industry should be encouraged to speed up development and testing of such systems. USGS personnel should be observers of such tests.

c. If it is determined that subsea production systems are preferable from an environmental standpoint, their use should be encouraged.

d. The cooperative USGS-API committee on standards should sponsor the preparation of standards and specifications of the safety and pollution control aspects of subsea production systems at the earliest appropriate time.

e. Concurrent with development and testing, USGS should begin the preparation of OCS Orders covering the use of subsea production systems.

IMPLEMENTATION ACTION REQUIRED

The Conservation Division should actively pursue each of the items in Recommendation No. 19.

APPENDIX

An Evaluation of "Energy Under the Oceans"--A Report of Study Conducted by the Technology Assessment Group, Science and Public Policy Program, the University of Oklahoma, August 1973[1/]

By W. A. Radlinski, Associate Director
U. S. Geological Survey

The technology assessment of Outer Continental Shelf (OCS) oil and gas operations made by a research team under the aegis of the Science and Public Policy Program, University of Oklahoma, is of special significance to the U. S. Geological Survey (USGS). We have the responsibility for the issuance of exploration permits and the supervision of operations authorized by leases on the OCS. And, it is our job to see that this work is done in accordance with the law--safely, without damage to the environment, and in keeping with optimum conservation practices.

The Survey's responsibility involves the management of over 1100 leases and nearly 2000 OCS platforms in the Gulf and 5 in the Santa Barbara Channel. These include over 6,200 wells and 10,000 well completions. Over 800 requests for permits to drill were processed in the past year. Platforms in the Gulf are as far as 98 miles from shore and are in water depths to 373 feet. The area of drilling and producing operations covers approximately 40,000 square miles. In the Santa Barbara Channel the platforms are about six miles from shore and are in waters up to 191 feet.

We also collect royalties from production at the rate of 16 2/3%. Last fiscal year this amounted to $360 million. Production in Fiscal Year 1973 amounted to 446 million barrels of crude oil and natural gas liquids, and 3 trillion cubic feet of marketed gas, with a total value of over $2 billion.

1/Prepared for the NSF-RANN Energy, Environment, and Productivity Symposium, November 19, 1973, Washington, D.C..

Accident reduction, pollution control, and environmental protection involve a number of factors, each of which contribute to an overall strategy. These include:

- o Stringent regulations insuring (but not limited to)

  good systems designs and construction,

  redundant safety systems,

  training of personnel,

  accident and equipment failure reporting,

  and corrective action procedures.

There are currently 12 OCS Orders covering the Gulf of Mexico area and 10 for the Pacific Area (Santa Barbara Channel), the only two areas where OCS operations are now being conducted.

Other elements of our strategy are:

- o An effective inspection program
- o Safety motivation of operators and employees
- o Research and development
- o Third-party review of our policies and procedures
- o Environmental assessments.

It is with these elements in mind, and with regard for problems of the future that can result from an acceleration of lease sales into new areas, deeper waters, and different environments, that I comment now on the Oklahoma report.

Overall it's a very good report. We welcome it at the Geological Survey and we intend to respond to each of the applicable recommendations.

In fact, we have already responded to many of them as a result of implementation plans we developed in response to recommendations of three earlier reports--one by a study team from NASA, another an in-house study by a team of USGS systems analysts, and the third by a panel of the Marine Board, National Academy of Engineering. A report of these plans is available from the USGS.

All four of the reports are compatible and many of the respective recommendations are the same, but the Oklahoma report goes much further than any of the other three. In-depth considerations of Government management and jurisdictions are unique to the Oklahoma study, as is its plan for OCS development. The recommendations from these sections will contribute importantly to "rational OCS policy making" and to "optimal resources development," to quote objectives from the purpose of the study.

Of the 12 recommendations under "Management of Technologies," 9 are aimed directly at the Survey and 3 at industry. Of the 22 recommendations on "General Policy and Management," 10 involve the Survey. And all of the items listed under the recommendation for "Specific Technologies" directly affect the success of our lease management responsibilities.

Referring now to the category on Management of Technologies, herewith is the status, in brief, on the 9 recommendations applicable to the Survey:

Standards -- Standards for the critical items of equipment are being developed under a joint API-USGS committee arrangement which involves OOC and WOGA.

These will be submitted to ANSI or other appropriate standards-setting organizations for review, and included in OCS Orders by reference. Quality control procedures for manufacturers are included.

Failure Reporting -- As announced in our press release of June 14, 1973, we intend to establish a failure reporting and corrective action system. A "safety-alert" system for immediate reporting to all lessees of equipment malfunctions, accidents or near accidents is already in effect.

Review Technology -- A Review Committee under the auspices of the Marine Board, National Academy of Engineering has already been established to serve as a third-party audit of our procedures and operations and to review state-of-the-art technologies.

Personnel Training -- A joint API-USGS committee is already working at establishing curricula and training requirements for operating personnel. We are also establishing formal training requirements for our inspectors.

Industry Cooperation -- The joint API-USGS committee on training is also developing programs for safety motivation. We have already gotten a Department of Justice opinion that information exchange in the interest of safety and environmental protection is not in violation of Anti-Trust Laws.

Subsea Production Systems -- The first OCS proposal for a subsea production system (i.e., more than one well) is presented in a draft Environmental Impact Statement now being aired publicly for the development of the Santa Ynez unit in the Santa Barbara Channel.

There are, of course, some conclusions and recommendations in the report with which we do not agree, and we are aware of disagreements by others, both pro and con. But this is to be expected from a 380-page report of a study as comprehensive as this one was. Disagreements are, of course, healthy, for they prompt dialogue and help bring out the facts. But in some cases, they have been presented out of context in support of an extreme position, either to discredit the entire report or as a basis for condemnation of all OCS development. It is important to recognize the overall objective of the study--to insure that development of the OCS is optimal in a broad social sense--and to recognize that individual recommendations are made in the context of improving, not condemning, OCS development. This is the way we in the Geological Survey are viewing it, and I feel certain this was the intent of the Assessment Group.

Our reasons for not agreeing with three of the recommendations in the Management of Technologies part of the report are as follows:

Accident Investigation -- We have not established a board similar to the National Transportation Board to investigate OCS accidents. Our present practice is to have all accidents

investigated by Survey personnel in accordance with fixed procedures. Major accident reports will be submitted to our Review Committee (mentioned earlier) for review. While we consider this procedure adequate for the present, we will give further consideration to the establishment of a separate board. We do intend that all reports of major accidents will be made public.

Personnel Standards -- We have not yet concluded that certification of company personnel is a viable procedure for insuring performance. Our present objectives are to establish required standards for training or experience before allowing operations to proceed. Certification, per se, involves numerous problems of establishing certification authorities, updating, employee union regulations, and State laws. We feel that training and experience standards may serve the purpose effectively.

Government R&D -- We have not established an in-house research, development, and testing program for a very practical reason--no funds. But that's not the total reason. We should have some capability for research, but we feel that the ultimate responsibility for safety and pollution prevention rests with industry. Accordingly, our approach was to establish an American Petroleum Institute (API)-USGS R&D committee to encourage industry in this activity. A list of pertinent R&D items under

investigation is being completed together with a list of those items that require new or improved development. We have informed industry that in those cases where they do not respond to R&D needs, the Government will undertake the work. But even so, public funds will need to be provided.

Concerning findings of other parts of the study -- the publication of a list of "Inadequate Components," called for in the recommendation under "Specific Technologies," will be a natural result of our aforementioned failure reporting and corrective action system. Further, these results will provide information to an established research committee to identify items for research and development. The lists of components to be developed, improved, and deployed will be passed on to the R&D committee and to a Standards Committee which is currently very active. The latter committee, by the way, has already drafted detailed standards for improved downhole safety devices which are currently being reviewed. Sand probe development and standards are high on the list of priorities.

Finally, I shall comment on the "General Policy and Management" part of the report. While we agree that promotion and regulation functions should remain divided between the Bureau of Land Management (BLM) and USGS to provide a continuous checking mechanism, we do not agree that the Survey should take the lead in preparing programmatic environmental impact statements. Programmatic concerns should remain the responsibility of BLM or the Council on Environmental Quality, as is the case in the environmental assessment of the Atlantic and Gulf of Alaska OCS. We, as well as National

Oceanic and Atmospheric Administration and many others, provide the geologic, geophysical, seismic, and other environmental data and analyses that are necessary for a full environmental impact assessment. I believe this procedure complies better with the intent, if not the organizational structure, of the study recommendations. The question of sufficiency of data is, of course, a budget problem.

Concerning the matter of concentration in the USGS of all management responsibilities on the OCS, we are currently working with the Office of Pipeline Safety to specify our respective roles. We have had meetings with the Occupational Safety and Health Administration along the same lines; we are developing understandings with the Environmental Protection Agency, and we do support the Federal Power Commission in providing estimates of recoverable gas reserves.

Lastly, by a recent policy decision, we are now publishing all new and revised OCS Orders in the Federal Register for public comment.

There have been numerous studies, reports, meetings, symposia, and legal actions concerning the development of the OCS. Several are in progress and many more will come. And this is as it should be--on the one side we have a need for the vast mineral resources that lie beneath the ocean floor, and on the other side there is a grave concern over the effects that the exploitation of these resources will have on the environment and hence our future well-being. The significance of the offshore to our national well-being, especially in these times of critical energy shortages, is clear when one realizes that over 11% of the total U.S. oil production and 13% of the gas production came from the OCS in the past year;

that this production is confined to a very small portion of those OCS areas which have petroleum potential; and that discovery and development will hopefully be accelerated as a result of tripling the offerings to three one-million acre lease sales per year.

The Oklahoma report has gone a long way in identifying means of improving development in this important area, and we commend both NSF-RANN and the University of Oklahoma on the study.

ATTACHMENT F

REPORT

ON THE

RESPONSES RECEIVED IN REPLY TO THE REQUEST

FOR

COMMENTS ON POTENTIAL FUTURE

OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Prepared by

BUREAU OF LAND MANAGEMENT
U.S. DEPARTMENT OF THE INTERIOR

Ed Hastey

Acting Associate Director

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HIGHLIGHTS

(As summarized from comments received)

- Responses: Industry, conservation and other interest groups, Federal agencies, State and local governments, private citizens.

- Results: Ranking of the OCS areas according to resource potential, leasing priority, and environmental concern.

- Greatest resource potential: (17 areas): Gulf of Alaska followed by central Gulf of Mexico and Beaufort Sea; Washington-Oregon OCS least resource potential.

- Leasing priority: (17 areas): Middle Atlantic first followed by Gulf of Alaska and Cook Inlet; Washington-Oregon OCS was last.

- Composite of above rankings: (17 areas): Central Gulf of Mexico followed by Gulf of Alaska; and west Gulf of Mexico; Washington-Oregon OCS was last.

- Environmental Hazards: Least potential danger to west Gulf of Mexico followed by the central and east Gulf of Mexico. The greatest environmental concern was expressed for the Alaskan OCS.

- Constraints to Production: Industry cites shortages of tubular goods, steel, drilling platforms, personnel as constraints.

- Environmental Groups: Cite need for more data collection and analysis with regard to frontier areas before leasing takes place in these areas.

- State and local governments: Cite pending litigation between Atlantic States and Federal Government that must be settled before leasing. Local governments stress need to protect environment adjacent to their areas.

Contents

Report on the responses received by the Bureau of Land Management in reply to the Request for Comments on Potential Future Outer Continental Shelf Oil and Gas Leasing

I. ABSTRACT

On February 20, 1974, in the Federal Register, there appeared a request for comments from all concerned groups on potential Outer Continental Shelf (OCS) oil and gas leasing (see Attachment I). The Bureau of Land Management and Geological Survey reviewed all the responses received and has determined several rankings of the 17 OCS areas that were delineated in the Federal Register Notice, on the basis of the responses. The Bureau received 63 responses, 25 of which were from oil or related industries. The remainder of the responses were from environmental groups, State and local governments and from private citizens. Detailed reviews of these responses follow in the remainder of this report.

In general, the oil companies responded with a ranking of the areas according to resource potential although a few companies also ranked the 17 OCS areas according to their individual preferences. Some of the companies, but not all, presented mapped data. Those which did so outlined areas of interest rather than individual geologic structures. Also, some companies, but not all, gave estimates as to time periods required to achieve initial and peak production and identified factors that may be constraints to development in the OCS areas. Although a

ranking according to environmental concern was requested in the Federal Register Notice, this particular request was not specifically directed toward the petroleum companies. Nevertheless, a few companies did submit a ranking according to relative degree of environmental hazard and this ranking as well as the others (ranking according to resources potential, leasing preference, and composite ranking) are presented in the text.

Specifically requested from environmental groups was a ranking of the areas according to environmental concern. None of the responses from environmental groups, however, presented this ranking. The consensus was that not enough information on the consequences of offshore development is available to make such a ranking. Likewise, the environmental groups which responded indicated that there is not sufficient information to indicate on maps specific environmental features or hazards. Instead, most of the responses called for increased study and analysis of the OCS environment before any decisions on leasing are made. The National Wildlife Federation (NWF) referred to the thousands of miles of estuarine shoreline and called for the protection of all these vital areas. NWF also discussed some guidelines they would like to see implemented to prevent pollution of the offshore environment during all stages of exploration, production and transportation. In response to the request for specific actions which may be taken to reduce or eliminate potential conflicts in certain areas between hydrocarbon activities and other activities in the areas, the National Oceanic and Atmospheric Administration and the Department of Transportation provided some guidelines. These, too, are presented in the text.

II. GENERAL PURPOSE OF THIS REPORT

In order to implement President Nixon's directive to lease 10 million acres in 1975, within acceptable environmental standards, and in order to implement more fully the purposes and objectives of the Outer Continental Shelf Lands Act, all concerned parties representing the oil and gas industry and the general public were invited to submit information concerning areas of interest for offshore oil and gas leasing and to identify problem areas. This has been done in order to help ensure that limited resources for exploration and development can be employed in the most promising areas consistent with environmental safeguards.

The specific regions that comments were to be directed towards are the following 17 Outer Continental Shelf (OCS) areas: North, Middle, and South Atlantic; East, Central, and West Gulf of Mexico; Southern California Borderland, Santa Barbara, North and Central California, Washington-Oregon; Cook Inlet, Southern Aleutian Shelf, Gulf of Alaska, Bristol Bay, Bering Sea Shelf, Beaufort Sea, Chukchi Sea. See Attachment II, Figure 1 for a map of these locations.

The information requested from industry included the following: (1) rank the areas by order of oil and gas potential, (2) outline of geologic structures of areas of interest shown on appropriate maps (the Federal Register Notice specified that responses would be held confidential upon request), (3) estimated time periods required to achieve initial and peak production after a discovery is made, and identification of factors constraining

development. The information requested concerning environmental factors included: (1) ranking according to environmental concern, (2) indication of specific environmental hazards to be considered, and (3) specific actions which may be taken to reduce or eliminate potential conflicts with oil and gas exploration and development activities.

The following is a report on all comments received from the petroleum and related industries, Federal agencies, State and local governments, and conservation groups. Because of the proprietary nature of some of the industry responses, company names are not identified with particular responses.

III. INDUSTRY RESPONSES

A. List of Companies Which Replied

The following companies responded to the request to express their views on the issues listed above.

Amoco Production Company

Atlantic Richfield Company

BP Alaska Exploration, Inc.

Cities Service Oil Company

Consolidated Edison Company of New York, Inc.

Continental Oil Company

Exxon Company, USA

Florida Gas Company

General Crude Oil Company

Getty Oil Company

Gulf Oil Corporation

Home Petroleum Corporation

International Corporation for Finance and Development

Marathon Oil Company

Mobil Oil Company

Phillips Petroleum Company

Shell Oil Company

Signal Oil and Gas Company

Southern California Gas Company

Standard Oil Company of California (Chevron)

Sun Oil Company

Tenneco Oil Company

Texaco, Inc.

Texas Eastern Transmission Corporation

Union Oil Company of California

B. Nature of the Data Received

These companies responded in varying degrees of detail both in regard to the narratives submitted, the quality and quantity of data, and maps of areas of interest on the OCS.

Each company has submitted data, maps, or information in its own particular format. Fifteen companies submitted maps. These maps varied greatly in detail; some indicated particular tracts of interest to the companies; others outlined regional geological structures and/or anomalies, whereas some indicated only general areas of interest. The companies submitted rankings of OCS areas by resource potential as requested. In addition, four companies have included in their responses other measures such as the desirability of one area over another for leasing because one area may meet their particular needs better than another area regardless of petroleum potential. Three industry rankings are presented on the next few pages: 1) by resource potential, 2) desirability of OCS areas with regard to leasing priorities, and 3) a composite list of the OCS areas with the most desirable areas listed first.

C. Ranking of the OCS Areas by Resource Potential, Leasing Preference and Composite Ranking

The ranking below is by resource potential of the OCS areas with those areas of greatest potential ranked first and the least potential ranked last.

Table 1

Rank by Resource Potential from the Greatest to the Least

1. Gulf of Alaska

2. Central Gulf of Mexico

3. Beaufort Sea

4. Bristol Bay

5. Southern California Borderland

6. East Gulf of Mexico

7. West Gulf of Mexico
   Mid Atlantic

9. North Atlantic

10. Santa Barbara

11. Bering Sea

12. Chukchi Sea

13. Cook Inlet

14. South Atlantic

15. Southern Aleutian Shelf

16. North and Central California

17. Washington-Oregon

Of the 25 industry responses, four petroleum companies ranked the frontier OCS areas according to relative leasing priority which follows; the ranking is in order of preference. (A frontier area is an OCS area in which no previous oil and gas development has occurred.)

Table 2

Ranking by Order of Preference with Most Preferred Frontier Areas Listed First

1. Mid-Atlantic
2. Gulf of Alaska
3. Cook Inlet*
4. Santa Barbara*
5. North Atlantic
6. Bristol Bay
7. Beaufort Sea
8. Chukchi Sea
9. Southern Aleutian Shelf
   South Atlantic
10. Bering Sea Shelf
11. North and Central California*
12. Washington-Oregon*

*Although there is development in Cook Inlet and Santa Barbara and there have been single lease sales off Washington-Oregon and North and Central California, they were ranked by the four companies, and, so, are included in this table.

If the two previous rankings are combined with one list indicating resource potential and leasing priority, the following is the result with the most desirable areas listed first:

Table 3

Rank in Order of Resource Potential and Order of Preference (Composite Ranking)

1. Central Gulf of Mexico
2. Gulf of Alaska
3. West Gulf of Mexico
4. Southern California Borderland
5. Mid-Atlantic
6. East Gulf of Mexico
7. North Atlantic
8. Bristol Bay
9. Beaufort Sea
10. Santa Barbara
11. Cook Inlet
12. Bering Sea
13. South Atlantic
14. Chukchi Sea
15. Southern Aleutian Shelf
16. Northern-Central California
17. Washington-Oregon

See Attachment II for a general map (Figure 1) of the 17 OCS regions, and see Figure 2 for the general locations of areas of interest within these regions. Attachment III is the matrix used in arriving at the above list and the reader is referred to this attachment.

D. Ranking of the OCS Areas With Regard to Environmental Hazard

Although no companies were requested to provide environmental rankings of the areas, four companies did rank areas according to environmental hazard. These four rankings are summarized and listed in order of increasing environmental hazard. Although factors affecting the environmental rankings were identified, a detailed analysis was not submitted. The Council on Environmental Quality (CEQ) report 1/ released in April 1974 also included rankings of certain OCS areas. They are presented for quick comparison. However, note that the CEQ report and subsequent rankings were concerned only with the Atlantic and Gulf of Alaska OCS.

Table 4

Industry Rank of Environmental Hazard from Least to Greatest	CEQ Rank of Environmental Hazard from Least to Greatest
1. West Gulf of Mexico	Eastern Georges Bank (North Atlantic)
	Southern Baltimore Canyon
2. Central Gulf of Mexico	(Mid-Atlantic)
3. East Gulf of Mexico	Western Georges Bank (North Atlantic)
	Central Baltimore Canyon
4. Northern-Central California	(Mid-Atlantic)
5. South Atlantic	Northern Baltimore Canyon
	(Mid-Atlantic)
6. Southern California	Southeast Georgia Embayment
Santa Barbara	(South Atlantic)
7. North Atlantic	Western Gulf of Alaska
Mid-Atlantic	Eastern Gulf of Alaska
8. Washington-Oregon	
9. Cook Inlet	
10. Chukchi Sea	

1/ OCS Oil and Gas - An Environmental Assessment, A Report to the President by the Council on Environmental Quality, April 1974. The report is in response to the President's April 18, 1973, directive asking CEQ to work with the Environmental Protection Agency in consultation with the National Academy of Sciences and other Federal agencies, to study the impact of oil and gas production on the Atlantic OCS and in the Gulf of Alaska.

11. Beaufort Sea

12. Bering Shelf
    Gulf of Alaska

13. Bristol Bay

Most of the 25 petroleum companies expressed belief that they could function in any OCS area under necessary environmental constraints for environmental protection. The majority of these companies referenced their past performance as proof of their capabilities.

E. Discussion of Related Factors

The following is a discussion of related factors such as time to initial production, time to peak production, material shortages, etc., as viewed by industry. Companies indicating extremely long periods to peak production, generally based their estimates on peak production for the entire area. Refer to Attachment IV for a tabulation of this information.

North Atlantic

Estimated time periods to achieve initial production after a discovery is made ranged from 3 to 8 years. The majority of estimated time periods to achieve peak production after a discovery ranged from 5 to 10 years with one oil company estimating 25 years for the entire area.

Specific factors that could constrain development in this area included shortages of drilling equipment, tubular goods, personnel, capital, and platform fabricating facilities, environmental restrictions, logistics due to distance from existing supply points, State-Federal litigation, existence in heavy shipping areas, fog conditions in summer months, and political constraints in relation to environmental protection.

Mid-Atlantic

Estimated tima periods to achieve initial production after a discovery is made fell in a 3-to-8-year range. Most respondent's estimates for tima periods to achieve peak production after a discovery is made ranged from 5 to 10 years; however, two oil companies estimated 18 and 25 years for the entire area.

Specific factors that could constrain development in this area included shortages of rigs, steel, personnel, capital, and platform fabrication facilities, environmental restrictions, logistics due to distance from existing supply points, State-Federal litigation, and political constraints in relation to environmental protection.

South Atlantic

Respondents estimated that it would take from 3 to 8 years for initial production to occur after a discovery is made. Most oil companies' estimates for time periods for peak production to be achieved after a discovery is made ranged from 5 to 10 years, with two companies estimating 15 and 25 years for the entire area.

Possible constraints on development reported were shortages in rigs, tubular goods, platforms, labor, and capital, environmental restrictions, and political constraints in relation to environmental protection. Although existing technology is adequate for exploration and production on the Southeast Georgia Embayment, the extreme water depths in the Blake Basin would require perfected deepwater technology. Because this area is hurricane prone, some delays/shutdowns in operations might occur during storm seasons.

Eastern Gulf

Respondents noted that an average range of 3 to 4 years would be required to initial production, although certain firms felt that as much as 5 to 8 years could be required in certain instances. Most respondents felt that 6 to 8 years would be the average range to peak production; however,

two firms felt 15 years to peak production was more accurate with two other firms observing that a minimal 4 to 6 years to achieve peak production would be required.

Several firms mentioned various constraints, including supply limitations on rigs, platforms, etc., while others noted skilled labor shortages, capital restrictions, and Department of Defense (DOD) constraints, such as conflict with Defense Warning Areas. One firm also made mention of environmental restrictions and regulations as being affirmative constraints, and another noted that if subsea completions were required for production, considerable testing would be required.

Central Gulf

Respondents noted that timing to initial production would be within the 2 to 4 year range, while time to peak production was estimated at 4 to 8 years. One firm noted, however, that production would be quite immediate (less than one year). Another firm differentiated between the oil peak and gas peak, noting that the latter would be a function of drilling completion and pipeline connection.

Of the constraints specifically mentioned, only general materials supplies were noted by a very few firms. One firm noted that if subsea completions for production were to be required, considerable experimentation should be forthcoming.

Western Gulf

Respondents noted that an average range of 2 to 4 years would be required to initial production (from discovery), and 5 to 8 years would be the average range required to obtain peak production, although one firm felt

that as much as 10 years would be needed for peak level production. Constraints mentioned included supply constraints on rigs, platforms, etc., and conflicts with DOD operations. Additionally, labor shortages were seen by one firm as a potential constraint, and one firm noted that if subsea completions were required for production, considerable testing should be forthcoming.

Southern California Borderland

It was noted by most respondents that the timing to initial production (after discovery) would be approximately 3 years, while peak production would occur approximately 8 years after initial discovery. However, a significant percentage of those companies responding stated that peak production could come between 10 and 15 years after discovery. Further, two firms felt that water depth would be the most important variable in both initial and peak production.

The principal constraints included the limited supply of rigs, tubular goods, platforms, and high seismic activity, with several firms noting that deep-water technology (beyond 1500 feet) may require several years to develop.

Santa Barbara Channel

Respondents noted that the timing to initial production would be about 2 to 4 years after discovery, with peak production coming within the 5-to-8 years range, although a single firm felt peak production would occur 12 years after discovery.

Constraints for this area included earthquake danger, some supply limitations on tubular goods, steel, etc., with some firms noting that subsea drilling and completion in deeper waters at greater distances from shore could also be a potential constraint.

Northern and Central California

Respondents noted timing to initial production would be about 3 to 4 years after discovery, although there was a very wide range of estimates of timing to peak production. Over 60% of the firms felt that peak production would occur between 5 and 7 years; over 25% of all firms estimated a range of 10 to 20 years to achieve peak production for the area.

Few firms noted specific constraints, with limited supply of tubular goods, rigs, and possible earthquake danger being explicity mentioned.

Washington-Oregon

Timing to initial production was generally 3 to 4 years, although two firms felt it would require as much as 6 years after discovery to achieve initial production. Six to 9 years was the range to peak production for most firms, but 3 firms estimated that it would not be achieved until 12 to 20 years after discovery.

Few firms mentioned specific constraints, but a few expressed concern over deeper water depths in excess of 600 feet, plus possible logistical problems, limited supply of tubular goods, somewhat poor weather, and seismic activity.

Cook Inlet

Estimated time periods to achieve initial production after a discovery is made ranged from 2 to 7 years. The majority of estimates for time periods to achieve peak production were between 4 and 8 years; two companies estimated tha period to be 15 and 20 years for the entire area.

Specific factors that could constrain development include remoteness from supply sources and markets, limited gas market, need to construct gas pipelines and shore facilities, prohibition on gas flaring, State-Federal ownership litigation, severe tides, environmental restrictions, and shortages of rigs, platforms, steel, personnel, and capital. Also the introduction of earthquake/ice problems will require new designs and increased safety guidelines for equipment and personnel for the Alaska offshore.

Southern Aleutian Shelf

Responses on the timing of initial production after discovery ranged from 3 to 8 years. Most companies indicated that peak production would be achieved within 6 to 12 years after discovery; one estimate was 20 years and another was 25 years for the entire area.

Shortages of rigs and platforms, high costs, severe sea and weather conditions, and limited gas markets would act as constraints on development. Large inventories of equipment and supplies must be maintained because of remoteness from supply points as well as

interruptions from supply points in severe storms. One company noted that North Sea technology supplemented with earthquake design engineering would allow relatively safe operations in shallow water areas where the sea bottom is not dissected.

Gulf of Alaska

Respondents indicated a time period ranging from 3 to 8 years for initial production to occur after discovery. Estimates for peak production after discovery averaged 10.5 years with two oil companies estimating 20 years for the entire area.

Constraints on development included shortages of rigs, platforms, steel, labor, and capital, limited gas markets, severe sea, weather, and seismic conditions, minor State-Federal disputes on State tidelands boundaries, and the need to maintain large inventories of supplies and equipment because of remoteness from supply sources.

Bristol Bay

Estimated time periods to achieve initial production after discovery ranged from 3 to 8 years. Estimates for peak production after discovery averaged 10.5 years with one oil company estimating 23 years for tha entire area.

Specific factors that could constrain development include shortages of equipment, manpower, and capital, remoteness from market and supply sources, limited time for drilling, and severe weather conditions including ice, high winds and waves, and dense fog.

Bering Sea Shelf

Estimates for timing of initial production after discovery ranged from 3 to 10 years. Responses on timing of peak production after discovery averaged 10.7 years with one oil company estimating 25 years for the entire area.

Factors which could constrain development include the short construction season, equipment shortages, remoteness from labor and equipment supplies, limited gas markets, and severe climate including thick ice and high winds. Although one company stated that present technology is capable of coping with problems of weather and thin ice, another maintained that existing technology is inadequate in dealing with the ice conditions in the northern part of this area. Still another stated that there is no available method of producing under the severe conditions of the Arctic ice pack with the exception of man-made islands.

Beaufort Sea

Estimated timing for initial production after discovery ranges from 3 to 10 years. The average estimated time period for achieving peak production is 11.7 years with one company estimating a 30 year time frame for the entire area.

Constraints on development include the permanent ice conditions, severe climate, limited open waters in winter, short construction season, shortages of labor and equipment, remoteness from markets,

high transportation costs, and the State-Federal disputed boundary around the barrier islands. Technology to handle moving ice packs may be developed by the mid- 1980's. Also, artificial islands could be built in shallow areas.

Chukchi Sea

Estimates for time periods for initial production after discovery range from 3 to 9 years. The majority of estimates on time periods for peak production after discovery fell in the 7-to-15 years range, with one company estimating 5 years and another estimating 25 years.

Constraints on development included labor and equipment shortages, severe climate and ice conditions, remote location, and the short construction season. There is no available method of producing under the severe conditions that exist with the exception of man-made drilling islands. Technology may be developed to handle moving ice packs by the 1980's.

See Attachment IV for a table of related factors which summarize this section.

IV. ENVIRONMENTAL AND OTHER GROUP RESPONSES

A. List of Respondents

The environmental groups that commented include the Alaska Conservation Society, National Wildlife Federation, Friends of the Earth, Sierra Club, Committee for Green Foothills, and the Oregon Shores Conservation Coalition. Two non-environmental groups responded which were the New England Fisheries Steering Committee and the League of Women Voters of North Carolina.

B. Discussion of Responses

None of the conservation groups or individuals that responded ranked the areas by environmental concern. The general feeling is that there is not enough information on the consequences of offshore development or environmental data available on the area for them, industry, or the general public to make such a ranking.

The need for BLM to have baseline studies in all the areas before making any decisions on leasing was stressed. These groups feel that at least three years of baseline studies are needed to adequately understand and protect the environment.

The most detailed of the environmental groups responses was from the National Wildlife Federation (NWF). In their letter of May 1, 1974, the NWF listed guidelines they would like to see implemented in order to protect the environment from damage during operations to extract oil and gas. These are:

1. Use of environmentally safe sound wave generating equipment
2. Finding a better way to dispose of drilling cuttings other than dumping in the water
3. Keeping a closer watch on the disposal of materials off the side of the platforms.
4. Employee education program to help prevent mistakes that lead to spills.
5. Better monitoring for blowout prevention
6. Improved pipeline construction techniques to minimize environmental damage
7. Improved tanker technology to prevent oil spills
8. Improved methods for oil spill clean-up operations.

The Sierra Club expressed concern about many areas, but stated, "Under a drastically accelerated program of offshore leasing, meaningful evaluation of 'areas of greatest environmental concern' and 'potentially significant environmental factors' is all but impossible." In the response from the Sierra Club were discussed some areas of "particular biological productivity, diversity or uniqueness". But, the Sierra Club warned that although the list is the best possible under the circumstances, it is incomplete and patchy. Finally, the Club urged that "the Department of the Interior not embark on any massive offshore development programs until adequate data is available on which to make reasonably informed judgements about the degrees of risk and benefit involved".

V. FEDERAL AGENCY, STATE GOVERNMENT, LOCAL JURISDICTION RESPONSES

A. List of Responses

Responses were received from the following Bureaus within the Department of the Interior regarding offshore areas: 1) United States Geological Survey, 2) the Bureau of Mines, 3) the Bureau of Outdoor Recreation, 4) the National Park Service, and 5) the Bureau of Sport Fisheries and Wildlife. Responses were received from the following Federal agencies: 1) National Oceanic and Atmospheric Administration, 2) Department of Defense, 3) Federal Energy Administration, and 4) Federal Power Commission. In addition, the Council on Environmental Quality's report on environmental considerations in the Atlantic OCS and the Gulf of Alaska, ordered by the President in April 1973, was released in April 1974. The reader is referred to the CEQ study for their assessment of environmental impacts on the Atlantic and Gulf of Alask OCS (also see the CEQ OCS ranking on p. 10 of this report).

B. Discussion of Federal Agency Responses

In addition to the Request for Comments that appeared in the Federal Register, the Bureau of Land Management requested resource reports from the aforementioned Bureaus within the Department of the Interior. In the request for resource reports, these Bureaus were asked to submit comments and data on their respective areas of concern. Summaries of each of these resource reports are given in the following text.

The USGS prepared a comprehensive geologic report on the structure and resource potential of each of the OCS areas. The United States Geological

Survey has estimated (March 1974) that offshore petroleum recoverable resources in the OCS to 200 meters water depth as yet undiscovered total 58 to 116 billion barrels. Undiscovered recoverable gas resources are estimated to be 355 to 710 trillion cubic feet.

The Bureau of Mines prepared an analysis of the supply and demand of petroleum until 1980. It is predicted that the demand for oil in 1980 will be 20.8 million barrels per day and for gas 34.5 trillion cubic feet per day. However, supply is estimated at 11.7 million barrels per day and 20.4 trillion cubic feet per day. These projections were made, of course, before Project Independence and the recent directive by the President to accelerate the OCS leasing program. In the present day tight petroleum supply situation, markets for petroleum are characterized by greater demand than supply. Depending on location of resources, certain patterns of processing and consumption likely would develop. That is, oil production from the Atlantic OCS would most likely be processed in refineries along the Atlantic seaboard and consumed in nearby eastern States. Likewise, gas from the Atlantic OCS would also be consumed in these areas. Similarly, production in the Pacific OCS would probably be processed and consumed in the Pacific seaboard and adjacent States. Increased oil production in the Gulf of Mexico is expected to be refined in Gulf coast refineries as is

currently being done. Because of past activity in the prolific Gulf of Mexico hydrocarbon areas, an extensive network of pipelines carries hydrocarbons to many areas of the country. Gulf of Mexico hydrocarbons serve 36 of the 48 coterminous States. Presumably some of the increase in production that would result from accelerated activity in the Gulf of Mexico within a few years will serve to satisfy the increased demand for petroleum in Gulf Coast States, but the remainder will likely be piped to the other States that depend on Gulf of Mexico oil and gas. Alaskan production probably will be processed on the Pacific seaboard for consumption in Pacific and western States.

The National Park Service, the Bureau of Outdoor Recreation, and the Bureau of Sport Fisheries and Wildlife have categorized according to location some of those Historic Sites, National Park areas, refuges, fishing areas, etc., that would be impacted by hydrocarbon activity. These reports have noted that the possible oil and gas lease sales in OCS areas represent many potential threats to the recreation environment. These reports assume a constant threat of damage from oil leakage or spills. The report also observes that construction of pipeline terminal stations and related road and facilities could eliminate some future opportunities for water-oriented outdoor recreation. They note that platforms and rigs visible from shore can have negative visual impacts and that their construction and operation may result in oppressive noise or objectionable odors.

Besides the resource reports requested from other Bureaus within the Department, the Bureau of Land Management contacted other Federal agencies for their responses to the questions asked in the Federal Register Notice. The agencies contacted were: 1) the Department of Commerce, 2) the Department of Defense, 3) the Department of Transportation, 4) the Department of Treasury, 5) the Environmental Protection Agency, 6) Federal Power Commission, and 7) the Federal Energy Amdinistration. The Council on Environmental Quality report on the environmental effects of OCS development on the Atlantic and Gulf of Alaska OCS areas was transmitted to the Department during the same period that other agency comments were requested. This report is now being reviewed in detail. The following is a summary of responses of other agencies received by the Bureau of Land Management.

The National Oceanic and Atmospheric Administration (NOAA) (Department of Commerce) has provided data gathered in relation to fisheries in the Gulf of Mexico, the South Atlantic and the Pacific. In these reports, they call for the following specific actions to preserve fishing resources from potential damage from hydrocarbon development activities. All of these actions have been implemented or are being considered by the Department.

1. Wells and platforms should not be located in coral reef areas.
2. Platforms should not be located on steep slopes, as these are prime fishing areas for species such as snappers and groupers.
3. Drill cuttings and muds should be discharged so as to settle outside areas of productive benthic assemblages.
4. Submerged wellheads should be capped below the surface of the ocean floor or well marked with buoys.

5. Wells should be spaced far enough apart to permit trawling operations in the area.

6. All construction debris should be removed and disposal should be onshore.

7. Pipelines to onshore facilities should be consolidated into pipeline corridors.

8. Pipeline corridors should be located so that they do not traverse estuaries or that they traverse the least sensitive estuarine area. Productive bays and marshes should not be disturbed.

9. Pipelines should be buried beneath the ocean floor. Where they cannot be buried, they should be well marked with buoys and all buoys must be maintained.

10. In areas where obstructions already exist on the bottom, wells should be located near the obstructions to reduce further loss of fishing grounds available to the trawl fishery.

11. Onshore facilities must be located outside productive estuarine systems.

In addition, NOAA recommended that in order to preserve unspoiled water environments, there should be no haphazard array of development sites. Rather, the sites of hydrocarbon activity should be arranged, to the extent possible, in small clusters separated by no less than 50 miles. NOAA observed that density greater than this will increase the severity of effect upon fisheries and other marine estuarine resources.

The Department of Defense stated a preference for reviewing each leasing proposal on a case-by-case basis as they have done previously. Therefore, DOD did not wish to issue a commentary that would be inclusive of the entire OCS.

The U.S. Coast Guard (Department of Transportation) made the following comments in regard to OCS leasing. The Bureau of Land Management should avoid leasing in navigation routes but if necessary, consideration might be given to relocating such things as traffic separation schemes and ocean dumping areas where feasible and reasonable. The response from DOT mentioned that there are fishing areas listed in the Code of Federal Regulations, but it appears that there is no regulation to isolate the fishing areas from the leasing of oil and gas properties.

The Federal Power Commission discussed what they consider may well be the primary policy question to be decided with respect to future OCS leasing programs. This question is whether to focus attention on the frontier area of greatest potential i.e., Alaska, or to lease acreage in each of the major offshore areas with the goal of obtaining a more diffuse supply. To develop the Alaska OCS may be the most economically efficient method but, if the areas for development are more diverse, the Nation will have a more assured supply of petroleum. In regard to environmental protection, the FPC called for greater cooperation among agencies and advanced planning to reduce potential conflict between environmental protection and oil and gas activity.

The Treasury and Federal Energy Office had no specific comments, but promised full cooperation if needed in the future.

C. Discussion of State Level Responses

Responses were received from:

Maine	Gov. Kenneth Curtis
New Hampshire	Gov. Meldrim Thomson, Jr.
New Jersey	Gov. Brendan Byrne
Delaware	Gov. Sherman Tribbitt
Maryland	Gov. Marvin Mandel
Virginia	Gov. Mills Godwin
North Carolina	Gov. James Holshouser, Jr.
California	Gov. Ronald Reagan Director, Department of Fish and Game

Most of the Governors of the Atlantic States called for deferring leasing action on the Atlantic OCS until such time as any litigation is concluded between the States and the U.S. Government over jurisdiction. Most of the Governors, in fact, suggested that priority be given to Gulf of Mexico and other areas and that Atlantic OCS leasing be forestalled. California advocates the resumption of drilling off its shores but only under the strictest environmental and safety regulations. None of the Governors provided any specific detailed information. However, some indicated that they may be inclined to respond with other information after resolution of the jurisdictional disputes.

D. Discussion of Local Jurisdiction Responses

Four responses were received from local jurisdictions, all in objection to any possible hydrocarbon activity at or near their locales. The city of Portmouth, New Hampshire, requested more environmental analyses, but the cities of Manhattan Beach, Rancho Palos Verdes, and Hermosa Beach, California, are unconditionally opposed to any offshore hydrocarbon activity.

VI. PRIVATE CITIZEN, OTHER RESPONSES

A. Discussion of Private Citizen Responses

About a dozen private citizen responded to the Federal Register Notice. The responses can be divided into two categories: those from the West Coast and those from New York. Responses from the West Coast called for further study of environmental systems. Note was made that the time period allowed for acceleration of offshore leasing (i.e., 10 million acres to be leased in 1975) is not sufficient even to identify areas of environmental concerns, much less perform detailed environmental analyses. One letter called for an inventory of marine resources; and the need to accelerate data-gathering right along with the acceleration of leasing so that environmental data will be gathered in sufficient quantity to keep up with leasing.

The responses for private citizens in New York were collected by Congressman John J. Rooney of New York. These letters from residents of Congressman Rooney's district were, without exception, opposed to any drilling off the coast of Long Island.

B. Discussion of Other Responses

Letters were received from three members of the U.S. House of Representatives: Congressman Gerry E. Studds, Massachusetts;

Congressman Charles A. Vanik, Ohio! and Congressman John J. Rooney, New York.

Congressman Gerry E. Studds:

Congressman Studds' comments referred to the Gulf of Alaska, North Atlantic, and environmental values. Concerning the Gulf of Alaska, the point was made that the Council of Environmental Quality (CEQ) Report states that more data is needed concerning biological, physical, chemical, technological, economic, and social parameters in that area.

With regard to the North Atlantic, specifically Georges Bank, Congressman Studds referenced the CEQ report and its comments to the effect that little is known about the potential biological impacts of oil spills on fisheries of that area. It was also pointed out that in 1961, Congress identified the seaward shore of Cape Cod as an area of national environmental importance when it created the Cape Cod National Seashore. Therefore, more data is needed concerning the likely movement of any possible oil from spills that might occur in that region.

Congressman Charles A. Vanik:

Congressman Vanik directed his remarks to the proposed accelerated OCS leasing program. The Congressman does not favor elimination of offshore leasing for oil and gas, but questions the proposal to

lease 10 million acres of the OCS in 1975. Congressman Vanik questioned the justification of accelerated leasing, and if acceleration comes about, what should be its extent; concern was also expressed about the benefits of accelerated leasing, the costs that must be balanced such as environmental values, the need for more energy, and alternates to the proposed action. The question was also raised about economic and technical constraints that face industry in developing the OCS under an accelerated schedule and steps that will be taken to meet these constraints. He stressed the need for an environmental impact statement on the 10 million acre proposal.

Congressman John J. Rooney:

Congressman Rooney submitted nine letters from residents of his Congressional District for the purpose of informing the Department of their views on developing oil and gas resources in the North Atlantic. The general theme of these letters was that the author's are against such activities off the shores of New York.

Congressman Rooney's comments were to the effect that he is intersted in the subject, and solicits the Department's views.

VII. CONCLUSIONS

In addition to the requested ranking of resource potential, some companies ranked the 17 OCS areas according to leasing priority and environmental values. The area generally considered to have the greatest resource potential is the Gulf of Alaska followed by the Central Gulf of Mexico. The area of least resource potential is the Washington-Oregon OCS.

Four companies ranked the frontier OCS areas according to leasing priority. The Middle Atlantic was ranked first followed by the Gulf of Alaska. The area of least interest in this regard is the OCS off Washington-Oregon.

A composite of both of these rankings, i.e., resource potential and leasing priority, results in a ranking of areas with the Central Gulf of Mexico first followed by the Gulf of Alaska, Western Gulf of Mexico, Southern California Borderland, and the Mid-Atlantic ranked as fifth. The OCS off Washington-Oregon again ranks last.

With regard to environmental values, four companies ranked the OCS areas environmentally.

The area of least environmental hazard is the entire Gulf of Mexico; the area of greatest concern is the Alaskan OCS with Bristol Bay representing the greatest environmental concern. Most companies stated that they can operate in an environmentally safe manner as indicated by past performance.

Various factors were indicated to be constraints on the development of the OCS, i.e., rig availability, casing, personnel, capital, platforms, etc. The companies state that it will generally take 2-8 years for initial production to initiate in new sale areas after discovery of petroleum resources, and from 5-10 years for peak production. However, a few companies state that the necessary time for peak production to occur in some OCS areas will take 20-30 years.

The environmental groups did not rank the OCS areas, but they observed that more data gathering and analysis is necessary before leasing occurs in frontier areas. In fact, these groups feel that our present knowledge is of such a limited nature, that ranking the areas according to environmental values is not possible.

Of the governmental agencies that responded, the Federal agencies submitted the most information which dealt with guidelines and safeguards. State and local governments generally submitted comments to the effect that leasing should not occur until resolution of litigation and until more baseline studies involving environmental values are concluded.

Responses from private citizens were generally opposed to leasing in frontier areas.

The Department of the Interior intends to use the information summarized in this report as well as information from the CEQ study of the Atlantic

and Gulf of Alaska OCS areas, other studies, including the baseline studies that Interior will soon have underway in frontier areas, and discussions with concerned State officials and representatives of industry and environmental groups to determine which frontier OCS areas should be developed. All development actions will be conducted in full compliance with the requirements of the National Environmental Policy Act of 1969.

VIII APPENDIX

Notices

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

POTENTIAL FUTURE OUTER CONTI- IENTAL SHELF OIL AND GAS LEASING

Request for Comments

In order to implement Presid rt Nixm's directive to lease ten million acres in 975, and in order to implement more ully the purposes and objectives of the Juter Continental Shelf Lands Act, all oncerned parties representing the oil nd gas industry and the general public re invited and encouraged to submit inormation concerning areas of interest or offshore oil and gas leasing and to dentify problem areas. This is being done n order to help ensure that scarce reources for exploration and development an be employed on the most promising reas consistent with environmental afeguards. Regulations or procedures lecessary to implement the other actions nnounced by the President in his nergy Message relating to Outer Continental Shelf (OCS) leasing will be subequently published for public comment efore they become effective and are not art of this request for comment.

Oil and gas resources of the coninental margin, including those beond the 200 meter depth contour, subect to jurisdiction of the United States re to be considered. Precise continental helf boundaries between the U.S. and pposite or adjacent states have not, vith some exceptions, been agreed. Acordingly certain areas are or may be ubject to dispute. No decision has been nade to undertake leasing in actually or otentially disputed areas while efforts re being made to reach agreement with he nations concerned. In this connection eference is made to the last sentence of Department of State Public Notice 320, ppearing in 35 FR 3301 of February 20, 970.

Leasing in the Cook Inlet of Alaska nd on the Atlantic OCS is contingent on esolution of the litigation between the 'ederal Government and the State of laska and Atlantic coastal states rearding areas of jurisdiction or an alterative resolution of the issues. Further, he President's Council on Environmenal Quality is conducting studies of the nvironmental impact of oil and gas proluction on the continental shelf of the tlantic Ocean and the Gulf of Alaska. lo leasing in these areas will be pernitted unless it is determined that oil nd gas exploration and development can roceed in an environmentally satisfacory manner. However, information conerning OCS areas of interest is being requested at this time in order to identify areas of special resource potential and of environmental value. It is the intention of the Department of Interior to conduct a call for tract nominations on more specific areas after consideration of the comments resulting from this request and, where appropriate, after resolution of State/Federal jurisdiction disputes and a determination from the CEQ Atlantic and Gulf of Alaska studies that development can proceed in those areas in an environmentally satisfactory manner. Information received in response to this request will also be considered in determining future leasing plans.

The areas to be commented on are as follows:

	Approximate location
Atlantic Coast OCS areas:	
1. North Atlantic	Bay of Fundy to Cape Code north of 40° N. latitude and south of.[1]
2. Mid-Atlantic	Cape Cod to Cape Hatteras between 40° N. to 35° N. latitude.
3. South Atlantic	Cape Hatteras to Key West south of 35° N. latitude.
Gulf of Mexico OCS areas:	
4. East Gulf	East of 88° W. longitude.
5. Central Gulf	Between 88° W. to 93° W. longitude.
6. West Gulf	West of 93° W. longitude to Mexican border.
Pacific OCS areas:	
7. Southern California Borderland	South of 34° N. latitude to Mexican border (except Santa Barbara Channel).
8. Santa Barbara	Santa Barbara Channel.
9. North and Central California	North of 34° N. latitude to California-Oregon border (except Santa Barbara Channel).
10. Washington-Oregon	Between California-Oregon border and Canadian border.
Alaska OCS areas:	
11. Cook Inlet	South of 60° N. latitude.
12. Southern Aleutian Shelf	West of 153° W. longitude.
13. Gulf of Alaska	North of 56° N. latitude, east of 153° W. longitude.
14. Bristol Bay	South of 58° N. latitude, east of 165° W. longitude.
15. Bering Sea Shelf	U.S. waters south of 66° N. latitude.
16. Beaufort Sea	Between 142° W. and 160° W. longitude.
17. Chukchi Sea	U.S. waters north of 66° N. latitude, west of 160° W. longitude.

[1] The line drawn from a point at: 42°19.9' N. latitude, 67°46.9' W. longitude, thence to 42°9.3' N. latitude, 67°40.0' W. longitude, thence 41°42.4' N. latitude, 67°28.8' W. longitude, and ending at 41°15.3' N. latitude, 66°58.9' W. longitude.

Other Areas of interest may be commented upon by appropriate area designation.

AREAS OF OIL AND GAS RESOURCE POTENTIAL

The following information is requested:

1. Rank by order of oil and gas potential the areas of interest listed above.

2. Outline of geologic structures of areas of interest shown on appropriate maps. All such information will remain confidential on request. Bureau of Land Management official leasing maps may be obtained from: (1) Gulf of Mexico Outer Continental Shelf Office, Suite 3200, The Plaza Tower, 1001 Howard Avenue, New Orleans, Louisiana 70113; (2) Pacific Outer Continental Shelf Office, 300 North Los Angeles Street, Los Angeles, California 90012; or, (3) Alaska Outer Continental Shelf Office, 121 W. Firewood Lane, Room 270, P.O. Box 1159, Anchorage, Alaska 99510.

3. For each area of interest, estimated time periods required to achieve initial and peak production after a discovery is made, and identification of specific factors that may constrain development for these areas.

AREAS OF ENVIRONMENTAL CONCERN

The following information is requested:

1. Rank with areas of greatest environmental concern first the above areas and indicate specific environmental values which exist and damages which might be incurred.

2. If possible, indicate the location on maps of specific environmental features or hazards to be considered in these areas if their resource potential is devel-

oped (locations where maps can be obtained listed above).

3. Indicate specific actions which may be taken to reduce or eliminate potential conflicts with oil and gas exploration and development activities.

The information should be submitted no later than May 1, 1974, in envelopes or packets marked "Request for Comments on Potential Future, Outer Continental Shelf Oil and Gas Leasing." The information should be submitted to Director, Attention 730, Bureau of Land Management, Washington, D.C. 20240. Copies of the information should also be sent to the Chief, Conservation Division, No. 600, U.S. Geological Survey, National Center, Reston, Virginia 22092.

GEORGE C. TURCOTT,
Associate Director,
Bureau of Land Management.

Approved: February 15, 1974.

JOHN C. WHITAKER,
Acting Secretary of the Interior.

[FR Doc.74-4196 Filed 2-15-74;4:51 pm]

ATTACHMENT II

Figure 1 indicates the 17 Outer Continental Shelf (OCS) areas for which information was requested. Figure 2 indicates the general areas of interest within the 17 OCS regions; these general areas of interest are not drawn to scale. These general areas of interest as placed on the map of Figure 2, were determined from maps submitted by 15 oil companies; the general areas of interest are summarized as follows:

Areas	Total	Companies that Expressed General Regional Interest	Companies that Expressed Particular Areas of Interest within the Region
North Atlantic	13	11	2
Mid-Atlantic	13	11	2
South Atlantic	12	10	2
Eastern Gulf of Mexico	13	9	4
Central Gulf of Mexico	12	8	4
Western Gulf of Mexico	13	7	6
Southern California Borderland	14	9	5
Santa Barbara	10	9	3
North-Central California	11	9	2
Washington-Oregon	10	7	3
Cook Inlet	14	13	1
Gulf of Alaska	15	14	1
South Aleutian Shelf	11	10	1
Bristol Bay	15	14	1
Beaufort Sea	14	13	1
Bering Sea	13	12	1
Chukchi Sea	12	11	1

Following is the matrix used in arriving at the composite list. The rows of the matrix are simply the numbered rankings submitted by each company for each OCS area. The numbers in the column titled "Average" are simple averages calculated from the sum of the digits in each row divided by the number of entries in that row. The lowest average was 3.82 (Central Gulf of Mexico) meaning that the Central Gulf of Mexico is highest in the companies' priorities. The corresponding rank of each of the 17 areas is given in the column titled "Rank".

Of 25 industry or related responses, only 22 ranked the areas; three did not submit a ranking scheme; one company's list was not suitable for inclusion in the matrix. That is, that company divided the 17 OCS areas into three groups, each group with a high priority and a low priority. Group I was Atlantic Coast - Gulf of Mexico and the highest priority was the Central Gulf of Mexico. Group II was Pacific Coast and the highest priority was Santa Barbara. Group III was Alaska and the highest priority was the Gulf of Alaska. Because of this arrangement, this particular company's rankings were omitted from the matrix, leaving 21 companies whose rankings were included.

Some companies did not rank all 17 OCS areas. For this reason, averaging each row was necessitated rather than a simple summation of the digits in each row. For example, the North Atlantic was

included in the rankings of only 20 of the 21 companies whose lists are included in the matrix. Therefore, the sum of the digits in the row "North Atlantic" is 131. Dividing by 20 entries yields 6.55, the number appearing in the "Average" column.

It should be noted that of the 21 companies included in the matrix, 19 of these companies listed the areas according to resource potential. However, four companies listed the areas according to desirability for leasing. Two of these four companies listed separately resource potential and desirability and for both companies, only their lists according to resource potential were entered into the matrix. The other two companies ranked the areas only according to desirability and did not provide a ranking strictly by resource potential. For these two companies, their desirability rankings were included in the matrix, even though 19 others were rankad by resource potential.

Thus, the following matrix was constructed and used to determine the composite ranking of 17 OCS areas according to information supplied by industry.

OCS Areas	Composite Ranking by Company (Companies not named)																					Average	Rank
North Atlantic	11	10	1	8	8	7	4	x	10	5	13	2	4	6	3	7	8	9	8	6	1	6.55	7
Mid-Atlantic	9	6	2	9	7	6	x	x	9	10	14	6	3	5	2	5	4	11	5	3	2	6.21	5
South Atlantic	16	11	9	12	14	8	3	x	14	13	15	11	8	15	11	8	11	16	10	11	5	11.05	13
East Gulf of Mexico	7	3	10	1	15	5	2	x	6	7	10	10	5	4	5	4	6	8	4	x	8	6.32	6
Central Gulf of Mexico	13	1	3	7	1	x	1	x	5	1	1	4	x	1	7	1	1	3	6	x	9	3.82	1
West Gulf of Mexico	4	8	4	11	4	1	5	x	7	2	5	9	13	2	8	3	2	5	11	x	10	6.00	3
Santa Barbara	10	4	6	15	11	x	x	1	16	16	2	x	x	3	10	2	16	2	15	2	12	8.41	10
Southern Calif. Borderland	5	7	5	2	10	2	x	3	2	4	3	x	12	9	12	10	3	4	7	x	11	6.17	4
Northern-Central Calif.	14	12	12	17	12	10	x	x	13	15	11	x	14	14	15	16	15	12	16	10	13	13.39	16
Washington-Oregon	17	17	13	16	17	11	x	x	15	17	17	x	15	16	17	12	17	17	17	12	14	15.39	17
Gulf of Alaska	1	2	8	4	6	4	6	4	1	3	9	1	1	12	1	16	5	6	2	1	3	4.10	2
Cook Inlet	15	13	7	14	9	3	x	2	11	12	8	5	11	10	6	11	7	7	4	4	6	8.75	11
Southern Aleutian Shelf	12	16	14	10	16	x	x	x	17	14	16	8	10	17	16	15	12	15	9	7	15	13.28	15
Bristol Bay	6	5	11	5	3	9	x	x	8	9	6	3	2	8	9	13	9	10	3	5	7	6.89	8
Bering Sea	2	14	15	6	13	12	x	x	12	8	12	13	6	13	14	14	13	14	1	9	16	10.89	12
Chukchi Sea	8	15	17	13	5	14	x	x	4	11	7	12	9	11	13	17	14	13	13	8	17	11.63	14
Beaufort Sea	3	9	16	3	2	13	x	x	3	6	4	7	7	7	4	9	10	1	12	13	4	7.00	9

x indicates no ranking.

Note: Not all respondent companies ranked the areas and some companies did not rank all 17 areas.

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ATTACHMENT IV

Table of Related Factors - (Refer to Part III. E. Discussion of Related Factors)

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
North Atlantic	3-8	5-10 (25)	Drilling equipment; tubular goods; personnel; capital; logistics; platform fabrications; litigation; heavy shipping area; fog
Mid-Atlantic	3-8	5-10 (18-25)	Rigs; steel; personnel; capital; platform fabrications; logistics; litigation
South Atlantic	3-8	5-10 (15-25)	Rigs; tubular goods; platforms; labor; capital; deepwater technology; hurricane storms
Eastern Gulf of Mexico	3-4 (5/8)	6-8 (4-6 min., 15 max.)	Rigs; platforms; labor; capital; DOD Warning Areas; possible subsea completion requirements
Central Gulf of Mexico	2-4	4-8	General material; possible subsea completion requirements
Western Gulf of Mexico	2-4	5-8 (10)	Rigs; platforms; DOD Warning Areas; labor; possible subsea completion requirements
Southern Calif. Borderland	3	8 (10-15)	Rigs; tubular goods; platforms; seismic activity; deepwater technology

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
Bering Sea	3-10	10.7 (25)	Construction season; equipment; labor; remote supply sources; limited gas mkt.; weather; ice; winds; technology
Beaufort Sea	3-10	11.7 (30)	Ice; weather; limited passage; construction season; labor; equipment; remote mkts., transportation costs; litigation
Chukchi Sea	3-9	7-15 (5-25)	Labor; equipment; ice; weather; remote supply sources; construction season

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
Santa Barbara Channel	2-4	5-8 (12)	Seismic activity; tubular goods; steel; subsea completion testings; deepwater technology
Northern & Central California	3-4	5-7 (10-20)	Tubular goods; rigs; seismic activity
Washington-Oregon	3-4 (6)	6-9 (12-20)	Deepwater technology; logistics; tubular goods; weather; seismic activity
Cook Inlet	2-7	4-8 (15-20)	Remote supply sources; limited gas mkt; pipelines; shore facilities; litigation; tidal activity; rigs; platforms; steel; personnel; capital; earthquake/ice
Southern Aleutian Shelf	3-8	6-12 (20-25)	Rigs; platforms; capital; weather; limited gas mkt; remote supply sources; weather; earthquakes
Gulf of Alaska	3-8	10.5 (20)	Rigs; platforms; steel; labor; caiptal; limited gas mkt.; weather; sea/sesimic; ligitation; remote supply sources
Bristol Bay	3-8	10.5 (23)	Equipment; manpower; capital; remote mkt./ supply sources; drilling time; ice; tidal activity; fog

ATTACHMENT G

COMMENTS ON

DES 74-90

"PROPOSED INCREASE IN ACREAGE TO BE OFFERED FOR OIL AND GAS LEASING ON THE OUTER CONTINENTAL SHELF"

BY

THE STATE OF ALASKA

COMPILED BY

THE DEPARTMENT OF LAW

INTRODUCTION

The State of Alaska has reviewed the Department of Interior's draft environmental impact statement on "Proposed Increase in Acreage to be offered for Oil and Gas Leasing on the Outer Continental Shelf". (DES 74-90). While the State acknowledges the difficulties inherant in the preparation of a programmatic environmental impact statement (EIS) of this magnitude, it nonetheless feels that the statement is materially deficient in terms of scope, analysis and timing, and thus does not meet the requirements of the National Environmental Policy Act.

The State's comments will be divided into three parts. In the first section, we will deal with the timing of the impact statement, focusing on those program actions which have occurred prior to the release of the draft statement. It is the State's contention that the cumulative effect of these actions is to render the program irreversible and the impact statement merely a justification for a program already conceded and partially implemented. The EIS comes too late to affect the decision-making process in any meaningful way.

The second section of the State's comments will concentrate on the scope and direction of the impact statement. The State agrees with the Environmental Protection Agency (EPA) that the impact statement fails to provide any insight into the relative costs and benefits of the Bureau of Land Management's (BLM) proposed five-year leasing schedule--particularly as that schedule relates to 1975 leasing in the Gulf of Alaska. This shortcoming is due to the total failure of the EIS to address the schedule, which was released shortly after preparation of the EIS.

The third section of our comments will contain an analysis of the EIS.

1. Timing

At public hearings conducted on DES 74-90 in Anchorage on February 3-4, 1975, substantial questions were raised as to the integrity of BLM's decision-making process in general and the EIS in particular. The public expressed doubts as to whether the EIS was not, in fact, merely a justification for a program already conceded and, in fact, partially implemented.

The State shares those concerns. It is a requirement of the National Environmental Policy Act (NEPA) that the decision-making analysis mandated by the Act be commenced at the earliest phases of program formulation. The impact statement must not post-date, and thereby justify, a program already commenced. For a period of two years, the Department of the Interior (the Department) has initiated actions, often involving substantial commitments of human and fiscal resources, in furtherance of the program proposed in the draft EIS. Regardless of the eleventh hour objectivity proffered by DES 74-90, the State shares the concern of many that these resource commitments will compel implementation of the proposed program. In addition, Department officials have made statements which question the "tentative" nature of the 10 million acre leasing proposal. In the final environmental impact statement, the Department should, with candor and completeness, discuss each resource commitment or other implementing action which has heretofore occurred and state why these commitments and actions in no manner compromise the integrity of the decision-making process. NEPA has been aptly described as an "environmental public disclosure law". A well written and timely environmental impact statement should disclose more than empirical insights into the decision-making processes of the responsible agency. The reviewing public must not only be apprised of the full scale of costs and benefits involved in the action; it must also be told the manner in which those costs and benefits have been weighed. It is, therefore, incumbent upon the Department to demonstrate that the impact statement is something more than a post hoc rationalization.

In discharging this function, the Department should address the following matters:

1. Substantial budgetary allocations have been made or requested by the Department in furtherance of the expanded leasing program. Substantial portions of these expenditures, or proposed expenditures, relate to pushing the program. For example, of the 63.7 million dollar OCS budget for fiscal year 1975, only 24.9 million went for baseline and special studies, while approximately 33 million dollars were allotted for resource and tract evaluation and lease management purposes. 1/ For fiscal year 1976, the Department has requested 99 million dollars to implement the proposed accelerated leasing program. The Department has invested great sums in furtherance of the program, making its substantial modification, or abandonment, unlikely or impossible.

2. The target figure for new OCS leases of 10 million acres per year was established by former President Nixon in his January 23, 1974 energy message. That figure resultedfrom a recommendation by the Department to the former president. 2/ In the case of California v. Morton, 3/ issue was taken regarding the Department's failure to prepare a programatic impact statement contemporaneously with the recommendation to Mr. Nixon. Indeed, this communication with the former president was clearly a recommendation for initiation of a major federal action significantly affecting the quality of the human environment. It is the State's contention that an impact statement prepared at that time was required.

1/ "OCS Budget--FY 1975," U.S. Department of the Interior.

2/ "This proposal originated with us," Sec. Morton told the Senate Committee on Appropriations, Hearings on H.R. 14434 (Special Energy Research and Development Appropriations for Fiscal Year 1975, 93rd Cong., 2nd Sess. at 67.

3/ Civ. #74-2374-AAH (D.C.C.D. Calif. 1974)

3. The programatic impact statement should have been prepared and reviewed prior to the holding of any lease sales in furtherance of the project. During the past 18 months, lease sales have been held in Mississippi-Alabama--Florida (sale #32), Louisiana (sale #33) and East Texas (sale #34). In addition, a call for nominations was held over a year ago for the Southern California OCS region (sale #35). Within the past two months, calls for nominations have been issued for the Gulf of Alaska (sale #39) and Bering Sea (sale #45). The Department has consistently maintained that a call for nominations does not constitute a decision to lease in any particular area. This may in theory be true. However, a call for nominations may preclude State advice at a critical point in time, since tracts ultimately selected for leasing are largely picked as a result of industry response to the call. Thus, because state and local officials are not consulted before a call is held, 4/ states are placed in a position of merely reacting to what is essentially an industry proposal.

4. The issuance by BLM, on November, 1974, of a five-year proposed OCS planning schedule was premature. The Department may maintain that the five-year planning schedule does not represent a decision to lease in any particular area. However, the Department, as well as other federal agencies, has represented the schedule in such a manner so as to compel, as a practical matter, adherence to it. In a press release communicating the schedule, BLM stated that "the new proposed leasing schedule is esstential as a planning document so that industry and government can allocate resources". 5/ It is, a requirement

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4/ In the Southern California experience, "according to state and local officials...the Department failed to consult or warn them sufficiently in advance of the announcement of the call for tract nominations; and the determination to issue the call was made unilaterally by the Department." "Outer Continental Shelf Oil and Gas Leasing Off Southern California: Analysis of Issues," National Ocean Policy Study, 93rd Cong., 2nd Sess., at 3. (Hereinafter "NOPS SoCal Hearings). Unfortunately, the same pattern of inadequate notice and coordination has developed in Alaska.

5/ "BLM Announced New Tentative OCS Lease Sale Schedule Through 1978," Bureau of Land Management Press Release, November 14, 1974, at 1.

of NEPA that no resources be commited prior to completion of the decision-making process mandated under that Act. Nonetheless, federal officals have encouraged the type of resource commitments which NEPA ideally precludes:

> It is important," an FEA official told the National Ocean Policy Study, "to establish a workable schedule which industry can rely upon to make appropriate investment decisions."

Indeed, these "appropriate investment decisions" are already being made in the Gulf of Alaska. During oral testimony at the Anchorage OCS hearings, it was revealed that the oil industry had already ordered exploratory drilling rigs specifically designed for Gulf of Alaska operations. Estimated costs for these exploratory rigs approach fifty million dollars each. At the hearings, BLM officiials expressed surprise at this anticipatory action. Nonetheless, the public statements of the Bureau of Land Management with reference to the purposes of the five-year schedule have made these types of commitments inevitable, and, in our opinion, irreversible.

5. Substantial national publicity recently was given to a December 18, 1974 memorandum from Deputy Undersecretary Jared Carter to the Directors of BLM and U.S. Geological Survey (USGS) calling for a "firm leasing schedule.. ...that definitely includes....a sale in '75 in both Alaska and the Atlantic". The meaning of that memorandum and its relation to the decision-making process mandated by NEPA is in need of clarification.

6. Actions of the Department, which indicate the accepted nature of the program, have been aired through the case of California v. Morton, supra. For example, the Department should address itself to the July 3, 1974 memorandum from William Grant, Manager of the Pacific OCS office, to Frank Edwards, Assistant Director Minerals Management, identifying the need to allocate $50,000

to probe local attitudes on OCS drilling, which would help establish "education thrusts toward these (state and local) officials at a later time, with a possib softening of their present opposition to offshore oil development". The State questions the wisdom of spending taxpapers' money to launch a public relations campaign for a program which supposedly is still in the review stage. The State is also distressed with the affidavit of Robert H. O'Brien in the case of California v. Morton, supra, which reveals that Mr. O'Brien was told by Jared Carter that he had been sent to the state to "sell" the merits of the OCS program to state officials.

7. The recent preparation of OCS operating orders for the Gulf of Alaska is of great concern to the State. These orders are currently being reviewed by State officials. The preparation of OCS orders at this time raises serious questions as to whether the environmental information being developed, will be later ignored. The Department takes a narrow view of the utility of environmental informationstating that, while this information will not be available to influence the decision to lease, it will nonetheless be valuable in structuring operating procedures for particular regions. 7/ It is thus distressing to find these orders prepared long before completion of even foundation work for adequate environmental analysis by the National Oceanic and Atmospheric Administration (NOAA). In the final environmental impact statement, the Department should address the need for and wisdom of preparation of OCS orders for frontier area operations at this early date, and should specifically indicate what environmental information has been used to modify these orders

7/ See "OCS Leasing Procedures and OCS Safety and Environmental Protection Activities of the Department of Interior," U.S. Department of Interior, Nov. 1974 at 1.

to the problems of particular frontier areas.

Moreover, it is not only the prematurity of these OCS orders which concerns the State. USGS has been criticized by the House Committee on Government Operations for its procedure of circulating and developing OCS orders in consultation with the oil industry prior to release of those orders to the public. 8/ In response, USGS specifically promised the committee that it would "no longer circulate draft orders to industry prior to initial publication in the Federal Register". 9/ Pursuant to the Freedom of Information Act, the State requested all drafts of OCS orders previously circulated to members of the oil industry. USGS supplied the State with final drafts which were released subsequently in the Federal Register, along with oil industry comments to prior drafts. However, the prior drafts were not made available to the State. In sum, the Department apparently has returned to its former practice of developing OCS orders solely in consultation with industry, limiting the role of state governments and the public to review of the Federal Register.

8. We question Secretary Morton's vow to the oil industry, in the midst of delicate controversy and during the time in which objectivity would seem indispensible, that he intends to "turn them loose over all outdoors." 10/ The Department's credibility seems further strained by Jared Carter's statement, quoted in the New York Times, that "to stop the world until those (OCS environmental baseline) studies were done would mean we couldn't hold any of the (Outer Continental Shelf) lease sales that we already have planned. We may lose a year's time in the effort of the entire industry". 11/

8/ "Our Threatened Environment: Florida and the Gulf of Mexico," 19th Report of the House Committee on Government Operations, 93rd Cong., 2nd Sess. (H.R. No. 93-1396) at 68-69. (Hereinafter "Our Threatened Environment").

9/ Id at 71

10/ "Morton Brings Optimism to the Oil Patch," Offshore Magazine, Nov. 1974.

11/ "Seven Cities on Coast to Fight Oil Drilling," New York Times, July 14,1974.

While these statements do not bind the Department in the formal sense, they underscore an important bias which has entered the decision making process.

Our list is not exhaustive, but it is indicative. In public hearings held in California, the National Ocean Policy Study group of the Senate Commerce Committee discerned a pervasive skepticism on the part of private citizens and state officials toward the integrity of BLM's NEPA review of the accelerated OCS program. 12/ As previously noted, the same doubts were raised at the Anchorage hearings. BLM has recognized that a programatic EIS must, by necessity address institutions as well as impacts. A critical institutional issue is credibility. The Department of Interior has an obligation to the reviewing public to place the program in proper perspective, and to demonstrate clearly that the decision-making process in which it is currently engaged will be objective, and possessed of the integrity which NEPA demands. There is great evidence to the contrary. This should be explained in the final statement.

2. In its comments on DES 74-90, the Environmental Protection Agency stated:

> "The assumed necessity for such a large sale necessitates immediately offering sizable acreage in all of the frontier areas. The Council on Environmental Quality recommended in their April, 1974 Assessment of OCS Oil and Gas Development that great care be taken in the development in frontier areas, and that the location and phasing of OCS leasing be designed to achieve energy supply objectives while minimizing environmental damage. This study documented the need for caution in development and assessed frontier areas in order of envir-

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12/ NOPS SoCal Hearings at 36-37

onmental risks. Some of these areas, especially the Gulf of Alaska, contain unique and vulnerable natural resources combined with significant natural hazards that would make precipitous development highly undesirable from an environmental standpoint. The accelerated development plan, as presented in the proposed schedule of 10 million acres, takes no cognizance of this assessment and further disregards the recommendations of the CEQ study. We feel that every effort should be made to phase leasing activity in frontier areas so that the most highly vulnerable areas will be protected from possibly irreversible adverse impacts of oil and gas development. This end would be well served by having the statement provide the rationale and environmental factors utilized in the selection of leasing areas. It would also be appropriate to provide the rationale for tract selection within specific areas. Clearly, such a scrutiny of areas could delay the need to prematurely enter environmentally sensitive or hazardous areas. This strategy would also allow more leasing in areas that are better ecologically known and thereby allow more adequate time for biological baseline studies in frontier areas". 13/

EPA's criticism centers on the fundamental defect of DES 74-90--that is, its failure to define and relate the program to BLM's leasing schedule. Thus, EPA specifically recommends that "the statement should also be coordinated with and include a justification for the anticipated order

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13/ U.S. Environmental Protection Agency Comments on DES 74-90, January 10, 1975 at 2. (Hereinafter "EPA Comments").

of lease offerings as depicted in the November, 1974 proposed schedule for leasing." 14/

An environmental impact statement must fully disclose the nature of the program insofar as the program has been formulated, and fully analyze the relative costs and benefits and reasonable alternatives. This type of analysis is wholly impossible in DES 74-90, precisely because the program is not defined in functional terms. The statement defines the proposed action as "the expansion of Outer Continental Shelf (OCS) oil and gas leasing to the point where 10 million acres are leased in 1975." (EIS, p.1) At page 7, the statement indicates that the leasing program "must include" frontier areas. Then, on page 18, the EIS states:

> "A schedule for 1975 is in the process of being constructed; it is this schedule that deals with the 10 million acre leasing effort for FY '75. An effort is also being made to construct a schedule for a period beyond 1975. However, neither schedule is complete at the present time."

The "program" goes far beyond the simple leasing of 10 million acres. The "program", is in reality, the information contained in the November 14, 1974 five-year leasing schedule. The environmental impact statement in no manner relates to that schedule, and gives no indication why, for example, the Gulf of Alaska has been slated for 1975 leasing. Clearly, this schedule has functional utility. The Department concedes that the purpose of this schedule is to allow the early allocation of resources in upcoming lease sale areas.

The State concurs with EPA in its request that the fiveyear schedule be incorporated in the environmental impact statement, and that the entire statement be redrafted to direct its discussion to the "tentative" timetable established in the schedule. This process will also make meaningful the

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14/ Id. at 3.

"Alternatives" section of the impact statement. A program which envisions leasing in the Gulf of Alaska in 1975 will have far different environmental impacts from a program which defers leasing in the Gulf until a later time. If the impact statement is to have meaning, it must provide a comprehensive analysis encompassing all frontier areas of the nation, and assessing them in terms of relative environmental risk, proximity to market, relationship to regional surpluses or shortages of oil, and to other potential reserves. This should then be coupled with various leasing scenarious and the environmental impacts of each disclosed.

This type of analysis is required by the National Environmental Policy Act. It has already been started by the President's Council on Environmental Quality in its April, 1974 report. By completing this analysis, the Department would be able to respond, not only to the conclusions and rankings of the CEQ report, but to observations on leasing priorities by EPA, the National Academy of Science and other federal agencies. Of course, the Department is not required to engage in a "crystal ball inquiry" in assessing the comparative impacts of various leasing alternatives. However, if the Department possesses sufficient information to rank areas in terms of early or deferred leasing, which it has done in its planning schedule, then it certainly possesses the information to assess the propriety of those rankings in the programatic EIS.

Certainly, the Department of Interior would seem under a heavy burden to do so. As the impact statement notes (EIS, p.3), former President Nixon had conditioned any leasing in the Atlantic or Alaska frontier areas upon the results of the CEQ report. The Bureau of Land Management has specifically adopted that decision-making criteria in numerous public statements. For example, in its February 20, 1974 notice in the Federal Register entitled "Potential Future Outer Continental Shelf Oil and Gas Leasing", the Department said:

"Further, the President's Council on Environmental Quality is conducting studies of the environmental impact of oil

and gas production on the continental shelf of the Atl[illegible] Ocean and the Gulf of Alaska. No leasing in these are[illegible] will be permitted unless it is determined that oil and [illegible] exploration and development can proceed in an environ[illegible] satisfactory manner."

Of course, the CEQ report made no such finding. But it did recommend that the expanded leasing program be conducted in a manner which would minimize environmental risks, noting that the Gulf of Alaska presents the highest risks to Outer Continental Shelf oil drilling of any frontier area--risks greater than in any area of the world where drilling has previously occurred. Specifically, the report concluded:

1. The northeastern Gulf of Alaska poses the greatest natural hazards to OCS oil and gas exploration of any area in the nation--risks greater than any area of the workd where drilling has heretofore occurred. (1-8).
2. In the summer, there is a 95 to 100 per cent chance of a Gulf of Alaska oil spill reaching shore--an over-all probability significantly greater than in any other area of the nation. (1-13)
3. Because of cold weather conditions, oil spilled in the Gulf will undergo less weathering than any frontier area (1-21).

4. The Gulf of Alaska is of unique and vital ecological importance and little is known of its populations or processes. (1-22).
5. Frequent storms, large earthquakes and tsunamis pose risks to gulf drilling not found in any other off-shore areas of the nation. (1-22).

6. OCS production of oil and gas from the Gulf of Alaska would provide more supplemental supplies of oil and gas than are needed on the West Coast and Alaska itself. (1-22).

7. The Gulf of Alaska is unique in its lack of infra-structure and on-shore facilities to handle on-shore development caused by OCS leasing activities. (1-24).

8. Oil clean-up and containment technology is grossly insufficient to handle Gulf of Alaska conditions. (4-23).

9. Richter Scale 7 and 8 earthquakes will occur on a regular basis in the Gulf of Alaska. Earthquakes of this magnitude could damage most OCS structures and would damage foundations possibly to the point of collapse. (5-6).

10. Off-shore oil storage in the Gulf of Alaska would result in mammoth oil spills due to storms, earthquakes and tsunamis--with potential spill amounts ranging to one million barrels. (5-11)

11. The Gulf of Alaska is more prone to frequent and severe earthquakes, tsunamis, ice and storms than is the Atlantic. The Council believes that oil and gas development in these hostile conditions increases the risks of environmental damage over that in the Atlantic OCS. (5-14).

12. Biological census and processes data in the Gulf of Alaska is particularly sparse. (6-47).

13. Of the areas studied, the Council concludes that, because of its tremendous ecological value as a habitat for many rare, endangered and important species, the longer physical residence time of ore, and its hostile environment, the Gulf of Alaska appears most vulnerable to major environmental damage from OCS oil and gas development. (6-47).

The question inevitably becomes: How can the CEQ report, which, before its release, had been adopted by the Bureau of Land Management as the express decision-making criteria for the program, be made consistent with BLM's decision to hold an early lease sale in the Gulf? Or, in the words of the Environmental Protection Agency:

> "Under these conditions, DOI must demonstrate why production in the Gulf of Alaska is a wise policy in view of (1) CEQ's determination that production in the Gulf of Alaska is environmentally undesirable, (2) that use of critical materials, primarily mobile substructures, is comparatively inefficient in terms of daily barrels recovered in the Gulf of Alaska compared to the Gulf of Mexico, (3) that production in the Gulf of Alaska is economically more expensive than in the lower 48 OCS areas, and (4) that production by 1985 in the Gulf of Alaska can be surplus to the nation's needs and should, at a minimum, be reserved for future years." 15/

EPA's recommendations are the inevitable result of a reading of the CEQ report:

> "Choices of technologies and operating procedures can substantially improve the viability of Alaskan OCS production. DOI should make an intensive study of technical

15/ Id at 5.

alternatives which would reduce risks of Alaskan production and plan to test those technologies so that their reliability can be assessed in other less severe areas. Only after advanced technologies and biological studies have proven that the risk is worth the benefit should a sale be held." 16/

The conclusion is similar to that reached by the Chairman of the Council on Environmental Quality, Russell Peterson. In announcing the CEQ study at an April 18, 1974, press conference, Peterson noted:

"In the high risk Alaska Gulf, CEQ found a high earthquake potential, very difficult operating conditions, and a good chance that spills would reach sensitive shoreline area."

Peterson noted that development in the high risk areas should not proceed until improvements in technology lower the risk. 17/

Echoing the responses of Peterson and the Environmental Protection Agency, the National Academy of Sciences, a partner in the preparation of the CEQ report, concluded:

"It is clear that the available data do not recommend the development of OCS resources at the present time in the Gulf of Alaska. First, data on weather condition, sea states, ocean currents, ecological system dynamics, fisheries resources, and the sensivity of indigenous species to oil pollution are not well known. Second, operating conditions, due to weather and sea states will be difficult, because storms are frequent, and their forecasts are less reliable. Third, the economic and social impacts of the

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16/ ID.

17/ Bureau of National Afairs, Environment Reporter, "Current Developments," April 26, 174 at 2130.

development on Alaskan coastal communities would be extreme. Finally, the frequency and severity of earthquakes and tsunamis in the area pose costly problems in engineering." 18/

The only public explanation of the federal government's abandonment of the CEQ report as a decisionmaking guide has been provided by the National Oceanic and Atmospheric Administration in its program proposal on Gulf of Alaska environmental baseline effort. The NOAA report stated:

"Formidable environmental issues surrounding petroleum development in this region were cited by the Council on Environmental Quality following a study of the impact of oil and gas development along the OCS, undertaken this past year at the request of the president. In its report of April 18, 1974, CEQ indicated that the northeastern Gulf of Alaska ranked highest in environmental risk among the areas studied, noting however, that 'particularily in Alaska, we have little or no information on existing marine life'." 19/

Noting the grave concerns contained in the CEQ report, NOAA nonetheless suggested reasons why the conclusions of that document were being ignored:

18/ "A Critique of "OCS Oil and Gas--An Environmental Assessment," National Academy of Sciences, op. cit. CEQ Report at NAS-21.

19/ "Environmental Assessment of the Northeastern Gulf of Alaska, First Year Program," National Oceanic and Atmospheric Administration, May, 1974, at 2.

"Because legal problems may delay development along the Altantic Coast, intensive interest has centered on the Alaskan OCS." 20/

The suggestion in the NOAA report--that the Department of Interior is following the path of least resistance in identifying areas for early leasing--should be dealt with in a final impact stat...

It is imperative that the Department thoroughly discuss the CEQ report in the final statment, including in its discussion the reasons the recommendations and conclusions of the report have been ignored in the fiveyear leasing schedule. If the department possesses independent information whch tends to negate the conclusio... of the CEQ report, that information should be provided in the statem...

In hearings before the National Ocean Policy Study group, (NOPS), Depute Undersecretary Jared Carter was asked by several Senat... what the precise decision-making criteria BLM would use in ranking areas for early or delayed leasing. The Senatorial study group was critical of the Department for its failure to delineate what variable... would be considered, and what weight would be given to those variables, in slating certain OCS regions for leasing. 21/ The Department should make clear the criteria which have been used in drawing up the five-year planning proposal, and should discuss each criteria in terms of the regions mentioned in the document.

20/ ID. at 1.

21/ Hearings before the National Ocean Policy Study of the Committee on Commerce, United States Senate, 93rd Cong., 2nd Sess., April 23May 22, 1974, at 50-57. (Hereinafter "NOPS Hearings").

In sum, the Department of Interior's decision-making process is unclear. The proper mechanism for correcting that deficiency is a revised draft environmental impact statement.

3. Analysis of DES 74-90

For purposes of clarity, the State will begin its analysis of DES 74-90 with three generic criticisms. Following this, a section-by-section analysis will be provided.

A. Relationship of OCS leasing to national energy policy.

The Environmental Protection Agency's criticisms of DES 74-90 state that "DES 74-90 fails to evaluate the necesssity or address the practicability of the size (10 million acres) of the proposed lease offering." 22/ This is a critical defect in the impact statement. Throughout the statement, often in unexpected sections, the Department makes assertions regarding the role of expanded OCS leasing in the national energy picture, and Sections 1E and 8F of the impact statement relate to this general question. But there is no thorough discussion of how OCS oil relates to the needs or shortages of the nation in a wholistic fashion.

Whether there exists a national energy policy, de facto or otherwise, is a question on which commentators may disagree. At the outset, however, it seems important that before the enormous risks which this proposal threatens occur, that the precise role of expanded OCS leasing in the national energy picture be defined, and its necessity and practicality thoroughly determined.

22/ EPA comments at 1.

The State commends the Department's section on energy conservation (Section 8(F)(6)). We agree with the Department's findings that "Energy conservation remains the critical area where an impact can be made on our demand-supply gap in energy resources." (EIS page 386). The citation and consideration of the Ford Foundation study "A Time To Choose" is commendable. 23/ What is lacking in the Department's section on energy conservation, however, is a discussion of the relationship of energy conservation to the need to accelerate development of the Outer Continental Shelf. Again, the State finds the CEQ report to be a much superior document in relating energy alternatives, such as energy conservation, to the possibility of limiting Outer Continental Shelf development.

Nowhere is this lack of analytical interrelationship more pronounced than in the EIS' consideration of the role of Alaskan OCS development to the PAD V market. For example, on page 23 of volume 1 of the impact statement, the Department makes the rather conclusory statement that "Alaskan production probably will be processed on the Pacific seaboard for consumption in Pacific and western states."

That assumption is contradicted by numerous sources. To begin with the CEQ report notes that, without Gulf of Alaska OCS oil, the Pacific states will nonetheless have an oil surplus by the year 19[illegible].

23/ A great many documents are available, of course, relating to or advocating energy conservation as both a short-term and long-term answer to the "energy crisis." In particular, the final EIS should consider "Energy Conservation," (UCLR 51488), L.S. Germain, Lawrence Livermore Laboratory (prepared for the U.S. Atomic Energy Commission), Novermber, 1973; and, "California's Electricity Quandry: III. Slowing the Growth Rate," Rand Corporation (R-1116-NSF/CSA), September, 1972.

Further, in the event that the proposed North Slope gas pipeline is located through Alaska and then shipped to the Pacific states, the west coast will have a 1985 total energy surplus which, according to CEQ, will further increase by the year 2000. 24/

The question of an imagined or real petroleum deficit for PAD V was one of the prime arguments given for construction of a trans-Alaska oil pipeline. Indeed, the Senate Interior Insular Affairs Committee, in considering S1801, (Trans-Alaska Pipeline Authorization Act), noted conflicting evidence on whether West Coast markets could absorb production from the trans-Alaska oil pipeline.

More recently, a report of the Senate Committee on Interior and Insular Affairs noted the likelihood of a PAD V surplus. 25/ The report acknowledges that variables, such as conservation efforts and production levels of petroleum in PAD V are difficult to factor in future projections. However, based on currently available information, the report said that market changes over the past year indicate the following:

"1. A reduction in West Coast petroleum consumption;

2. An increase in expected district production outside the North Slope;

3. A narrowed oil price differential between Japan and the U.S. West Coast (which thereby increases relative attractiveness of exports to Japan);

4. A dramatic increase in the expected profit per barrel from Alaska oil in all of the potential markets; and

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24/ CEQ Report, 3-13--3-18.

25/ "The Trans-Alaska Pipeline and West Coast Petroleum Supply, 1977-1982," Senate Interior and Insular Affairs Committee, 93rd Cong., 2nd Sess. (November, 1974).

as a result of the foregoing; and

5. A diminished range of North Slope outputs that would at once be (a) too great to maximize profits in West Coast markets, but yet (b) too small to offset diminished revenues in District V with increase revenues in another market.

"It is likely, however, that such an interval, in which increased output means lower profits, will still exist when and if North Slope production (plus other District V production) begins to outstrip District V consumption at prevailing prices. It is quite conceivable, therefore, that one or all of the producer interests on the North Slope would at some point regard it as advantageous to restrict production, even if....the United States as a whole were still deficient in crude oil in secure sources." 26/

The Interior Insular Affairs Committee chairman, Senator Henry Jackson, wrote letters to the Department of Interior and major holders of Prudhoe Bay reserves to determine if they expected petroleum surpluses to develop once the trans-Alaska pipeline reached production. The results of this survey were published in the report:

"The Interior Department's low and high demands variants, and ARCO's projections, all imply a shift in the District V from a deficit to a surplus position after 1979; Exxon's forecasts imply a deficit continuing through 1981...the greatest 1982 excess is that implied by Interior Department's low demand forecast (1.5 MMB pd), and the lowest is that of Exxon which indicates approximately equal production and comsumption in the District."

26/ Id at 26.

"Despite the difference in the level of deficit or excess forecast by the various respondents, there is one pattern they have in common; the District V deficit diminishes and/or the excess grows, beginning with the first year of pipeline operation and throughout the entire period. This pattern is quite at odds with public forecasts of industry and administration spokesmen prior to the 1973 passage of the law authorizing construction of the Trans-Alaskan Pipeline; at that time it was asserted that an excess (if it developed at all) would occur only at the beginning of production, would be small, and would probably disappear as District V demand again out-stript the new addition to supply." 27/

These recent predictions of a substantial energy surplus in PAD V have been supported by industry. After the announcement that initial production from the Trans-Alaskan Pipeline would increase from 600,000 to 1.2 million barrels per day, many oil company officials expressed concern over the ability of Alyeska to market the oil in the Pacific states, absent a drastic increase in West Coast comsumption. 28/ All this, of course, without a drop of Alaska OCS oil. Given the well-nigh universal view of both industry and government that a surplus of oil will exist in the Pacific states with Alaska OCS oil, certain marketing options for Alaska OCS oil become apparent:

27/ Id. at 14.

28/ "If West Coast demand increases at a swift enough pace between now and 1977, it can absorb all the new North Slope crude by backing out imports...If, however, the rate of gain slows down to around 3%, in contrast to an historic 5% or 6%, there may be a surplus." "Initial Alyeska Pipeline Capacity of Double," The Oil and Gas Journal, July 22, 1974.

1. Restrict production of Alaska OCS oil until more favorable price conditions are achieved;
2. Market Alaskan OCS oil to Japan, perhaps in exchange for Mid-East oil credits;
3. Return to the traditional practice of advertising and promoting wasteful oil consumption in the Pacific states, in the hopes of manufacturing a market where currently none exists.

Alaska OCS oil be of great speculative value to the oil industry, but of little value to the American public. The obvious question becomes: Why engage in precipitous oil exploration in the OCS region of greatest environmental risk and most environmental value, when the oil from the area is simply not needed in the areas of the United States where marketing is practicable. Obviously, this is not addressed in the impact statement. The final EIS must assess each OCS region in terms of marketing restraints, and must address the issues presented by a PAD V oil surplus.

The CEQ report agrees with the Department that, except in Alaska, most OCS oil will be consumed regionally. For other regions of the country, quite obviously, this is a major selling point for OCS oil and gas production. Locally produced oil on the Outer Continental Shelf, in the long run, will restrict the need for substantial tanker traffic generated by imports from other parts of the nation, or other countries. However, the vast bulk, if not the entirety, of Alaska OCS oil may be exported to find a market. Therefore, Alaska is in the unique position of facing both a rise in off-shore activity, and a concomitant increase in oil tanker traffic. Because of the singular danger of tanker activities in any area, and particularly in the Gulf of Alaska, the Alaskan OCS area should be singled out in

the Department's comparative matrix as facing added risks above those of other OCS regions.

The draft impact statement asserts that, in hospitable environments, shallow platforms may reach production from 3 to 6 years after the field has been discovered and its size determined. "Production from underwater completions in 1000-3000 foot water depths should be available in the mid-1980's". (Page 69).

Then, on page 70, the Department makes a statement applicable to the Gulf of Alaska:

> "Development of the environmentally hostile areas of earthquake zones, heavy moving ice fields and unstable bottoms would require additional study and, thus, more time."

The assertion raises substantial questions not only as to research and managerial lead time, but also to lead time due to rig and material shortages. Substantial criticism of the Department's proposal was given in EPA's comments on the impact statement, which asserted that not only would material and rigs be unavailable to expeditously develop 10 million acres per year, but that also, exploration in the Gulf of Alaska would not be completed until after 1988. 29/

Assuming Gulf of Alaska oil will play an intregal part in PAD V energy supply for what time period is this supply projected? In the impact statement, many alternative energy sources are rejected as "short-term" answers to our energy needs. However, based on EPA's figures, greatly accelerated Outer Continental Shelf oil development, particularly in the Gulf of Alaska, will just as assuredly not provide additional energy sources for many years, perhaps well into the 1990's. Given this necessary lead time for Gulf production, would not this

29/ EPA Comments, "Specific Comments at 1.

lead time also make feasible both long-term energy conservation, as well as development of alternative energy sources?

B. Role of Baseline and Special Studies

The CEQ report is replete with observations on the paucity of knowledge which exists as to populations or processes in the Gulf of Alaska. In summing up the CEQ report, Russell Peterson told the National Ocean Policy Study:

> "We also recommend that we need to obtain a substantial amount of baseline data before anything is done in these areas so that we can appraise the damage which might occur and, if it does, some limitation on development or additional control should be activated at that time." 30/

The need for substantial environmental information both as to population and processes, particularly in the Gulf of Alaska, has been noted by numerous other concerned officials. The National Ocean Policy Study (NOPS) has recommended that, "several steps be taken prior to leasing in frontier areas, including:

> "B. Environmental baseline studies of proposed leasing areas which are currently under way, should be completed, publised, and evaluated by CEQ and the NAS review panel." 31/

Testimony from various persons at the NOPS hearings emphasized the lack of existing data on such crucial variables as the effects of chronic low-level oil pollution on eggs, larvae, and migrating species.

30/ NOPS Hearings, p. at 12.

31/ "Outer Continental Shelf Oil and Gas Development and the Coastal Zone," National Ocean Policy Study, 93rd Cong., 2nd sess., at 6. (Hereinafter "OCS and the Coastal Zone")

Dr. William J. Hargis, Jr., Director of the Virginia Institute of Marine Sciences, stated:

> "In shallow or coastal areas there is little knowledge of the acute effects of the exposure to oil in the various stages of the life histories of either benthic orpelagic species, particularly on the sensitive portions of life stages such as eggs and larvae of fish, crab and shellfish. The same may be said for the chronic effects of exposure to low-levels of hydrocarbons." 32/

Quoting from the Ford Foundation policy project on oil spills, the NOPS group noted:

> "At present, assessment of the environmental impact of (off-shore oil and gas exploration and production) must be made in considerable ignorance and uncertainity because of the large knowledge gaps and conflicting opinions. Because so many serious questions remain unanswered, and because of the alarming implication of some of the information available, we recommend great caution in making policy decisions involving oil and the marine environment.. ..The only remedy for our uncomfortable ignorance is more and better research into the problem--especially in the more neglected aspects, such as chronic pollution and sublethal effects." 33/

32/ Id. at 13.

33/ Id at 15.

In testimony before NOPS, Hargis also noted:

"Current knowledge of continental shelf and slope circulation is inadequate...34/. "The ability to respond to chemical clues in the environment is particularly critical to migrating species such as shad, herring, striped bass which stretch through the entire coast, and salmon which is the northern or north Altantic species. Some research is being sponsored in these areas by both industry and regulatory agencies. However, the results of these research efforts, unless greatly expanded, will probably not enable us to precisely determine impacts of oil toxicity within the next few years." 35/

Again, Dr. Hargis noted:

"Baseline data are needed on the marine resources and environments involved. Several years ago, acquisition of such data was urged. Our arguments were lost in the din. Now it is very late. We must move quickly and the task is a complex one. Detailed socio-economic data are also required to properly assess costs, benefits, and tradeoffs." 36/

Dr. Hargis stated that three years was the minimum time required before even fundamental baseline data could be acquired. 37/ Dr. Hargis's concerns were shared by the Environmental Protection Agency during the same hearings. EPA's concerns were amplified by their comments to DES 74-90:

"In this connection, we feel the environmental baseline work being done on various OCS areas should be completed and analyzed before development is permitted. It is impossible

35/ Id at 137

36/ ID at 149.

37/ Id at 159.

to adequately evaluate the total environmental scenario of any of the proposed leasing areas at this time, and the prediction of environmental consequences depends upon the compilation and analysis of adequate baseline data." 38/

The concerns of the National Ocean Policy Study, the Council on Environmental Quality, the Environmental Protection Agency and numerous concerned private experts have been shared by the National Oceanic and Atmospheric Administration. NOAA, which has functional responsibility over federal baseline efforts, has stated:

> "Among environmental scientists within and outside the Federal Government, there is broad agreement that the baseline environmental studies must be undertaken immediately in potential leasing areas to precisely quantify our present subjective understanding of the risks of OCS development. Without quantification of these risks, a balance against the kenelitc of development cannot be drawn." 39/

The "Report" of NOAA Scientific and Technical Committee on Marine Environmental Assessment" is a critical document in analyzing the role and necessity of environmental baseline studies. That document concludes that the necessary role of environmental baseline studies are to "provide a basis for a prior prediction of the environmental impact of the proposed offshore development." 40/ Moreover, the report states that it will take between 3 and 5 years to develop adequate baseline data on populations and processes in order to sufficiently predict the impacts of proposed oil and gas activity. 41/ This is

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38/ EPA Comments at 3.

39/ "Environmental Assessment of the Northeastern Gulf of Alaska," op. cit. n. 19, at 3.

40/ "Report of the NOAA scientific and Technical Committee on Marine Envornmental Assessment," August 20, 1974 at 3. (Hereinafter NOAA Committee Report").

41/ Id at 9.

particularly true with reference to one of the most poorly understood problems of off-shore oil development--that is, the impact of chronic low level oil pollution on marine biota. The report acknowledges that "experiments on toxicity of oil to sub-Arctic marine organisms may be the key to predicting the impact of OCS development in the Gulf of Alaska". 42/ However, the report, quite candidly, concedes that information on this critical impact may not be sufficent even at the end of the 3 to 5 year period. 43/ This shortcoming is exemplified in the Gulf of Alaska case study provided in the report, where it is noted that, "we will not be able to predict or assess with assurance the long-term or low-level effects of development on the biota. Experimental data on sublethal effects obtained during the 4 year-study program will not be adequate for long term predictive purposes. Food change dynamics and bio-accumlations processes will not be understood." 44/

The problems inherent in baseline data accumulation in any OCS area are aggravated in the Gulf of Alaska, due both to the present paucity of historical data, and severe weather conditions which will stringently limit available field research time. The inescapable conclusion from the NOAA report, as well as the other sources previously mentioned, is that the Department of Interior will not be able to predict with any degree of certainty the environmental impacts of Outer Continental Shelf oil and gas development in the Gulf until years after the proposed date for leasing.

42/ Id at 6.

43/ Id at 59

44/ Id

Yet despite the recommendations of concerned federal agencies, as well as state and private officials, the Department is nonetheless willing to blindly proceed into the Gulf of Alaska. We previously referred to Jared Carter's comment that baseline studies should not be allowed to hold up lease sales that "we already have planned." In the impact statement, at page 339 of volume 2, the Department amplifies on Mr. Carter's comment:

> "A central feature of many of these studies is that they are never really completed in the sense that they rarely reach definitive conclusions with wide applicability, but simply advance from one state to another, from one level of analysis to another, thereby contributing to a growing area of knowledge and body of literature pertaining to the numerous complexities of environmental analysis. To delay the sale on the basis of incompleted studies would require an indefinite delay perhaps of many years duration."

The statement is at once unsupported and insensitive, and totally unresponsive to the serious reservations voiced by several federal agencies. Particularly in the Gulf of Alaska, we are far from the point of "diminishing data returns" that the Department of Interior seems to suggest. NOAA, in its Scientific and Technical Committee Report, has identified critical data gaps which can be filled within a period of 4 or 5 years. At that time, sufficient information will be available to determine not only whether to lease, but also how and under what conditions to open a frontier area. The Department's cavalier attitude towards the role of environmental studies does little but aggravate the growing skepticism felt by the public towards the program begin reviewed in DES 74-90. The Department does not

know what the impacts of oil and gas development in the Gulf of Alaska will be. Neither does it know the particular risks that will be faced by Gulf drilling. By proceeding in ignorance, the Department concedes it is willing to sacrifice the richness of other resources which are present in the Gulf of Alaska, in order to exploit oil and gas.

In extrinic documents, the Department of Interior has suggested that although the decision to lease will admittedly be uninformed the baseline data will nonetheless be valuable in developing specific operating procedures in the varying regions. 45/ However, in the impact statement it is noted that operating orders for frontier areas will be similar to those in the Gulf of Mexico. 46/ Moreover, the State would also note that, despite the fact that baseline efforts in the Gulf of Alaska have barely begun, draft operating orders for the Gulf have already been prepared and throughly reviewed by the oil industry.

In summary, the environmental baseline data which will be gathered by the National Oceanic and Atmospheric Administration, and by other sources, will have no functional value in BLM's decision-making process. Because of the bonus bidding system used by the Department of Interior, massive commitments of fiscal resources will be made at the earliest stage of operations--that is, the lease sale itself. Once the lease sale is held, practicability would determine that, regardless of how revealing the subsequent baseline data is, the weight of investment would compel development of the leases.

45/ See note 7.

46/ DES 74-90, Vol. 1, p. 8

The Council on Environmental Quality has critized past OCS orders as being all too acceptable to the oil industry, reflecting nothing more than existing commercially feasible technology. 47/ Put another way, sensitivity of receiving waters in surrounding environments has not been considered. Indeed, the Department believes it uneconomical to require application of the best demonstrated control technology. 48/ In the final environmental impact statement, the Department should deal in a much more complete and candid way with the question of the role of environmental studies. Specifically, at what points in the decision-making process will the environmental studies be of value, and what weight will they be given in determining either whether to lease, or in establishing particular operating conditions to be imposed upon the operators.

C. Analysis of the program under the National Environmental Policy Act, the Outer Continental Shelf Lands Act and the Endangered Species Act

Before engaging in section by section comments on the impact statement, it would seem helpful to take a step back and look in overview, at the proposed 10 million acre program in terms of the laws under which it must be formulated. The requirements of the National Environmental Policy Act and other relevant legislation are at once programatic and specific. In this last general section of the State's comments, we would like to reflect on the program as it relates to these legislative acts.

Section 101(a) of the National Environmental Policy Act imposes upon each federal agency the obligation "to use all practicable means and measures including financial and technical assistance, in

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47/ CEQ Report, 9-19.

48/ DES 74-90, Vol. II, p. 426

a manner calulated to foster and promote the general welfare, to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of American." In furtherance of this mandate, Section 101(b) of NEPA sets six goals which the act strives to achieve. Among them are:

1. "Attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable or unintended consequences"

The Department of Interior's program, as contained in the five-year planning schedule, assumes massive leasing in every frontier area of the nation. In the planning schedule, no consideration is given, even on a preliminary basis, to the exclusion of certain areas for oil and gas development where such activity might cause "undesirable or unintended consequences", Throughout Interior's program is the suggestion that Outer Continental Shelf oil and gas leasing is the primary beneficial use of each OCS region. As we have demonstrated in previous sections of these comments, the Department is willing to engage in oil and gas development in the Outer Continental Shelf regardless of the consequences to other resources, otherwise, the Department would clearly defer drilling until it knew what impacts oil and gas development would cause to these other resources. The State would suggest that this position falls short of attaining "the widest range of benefical uses of the environment."

2. "Preserve important historical, and cultural and natural aspects of our national heritage, maintain, wherever possible, an environment which supports diversity and variety of individual choice";

As will be more fully developed in our discussion of the Endangered Species Act, the Council on Environmental Quality has stressed the ecological importance of the Gulf of Alaska. The Gulf is home to a wide range of species that were once common throughout the world, yet now find their last refuge in Gulf waters. To expose these species to oil development without knowing what impacts development will have upon them, makes little headway toward preserving these natural aspects of our national heritage.

3. "Achieve a balance between population and resource use which would permit high standards of living and a wide sharing of life's eminities";

The requirements of Section 101(b) (5) of NEPA relate directly to our previous comments on the impact statement's lack of analysis on the relationship of the 10 million acres proposal to our country's energy needs. How, we ask, can the Department of Interior "achieve a balance between polulation and resource use" if the role of the program in achieving that balance is nowhere discussed or analyzed?

4. "Enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources",

The impacts of Outer Continental Shelf oil development on renewable resources are likely to be immense. One of the critical gaps of the CEQ report, noted in the NOPS hearings, is the lack of knowledge on the impacts of the OCS development on commercial and sport fisheries.

The Department has chosen to exploit a finite resource regardless of the impacts on significant renewable resources. The mandate of section 101(b)(6) of NEPA seems ignored.

Section 102(A) of NEPA requires that federal agencies utilize a "systematic, interdisciplinary approach which will assure intergrated use of the natural and social sciences and the environmental design arts in planning and decisionmaking which may have an impact on man's environment." We have already noted that the Department has ignored the recommendations of other concerned federal agencies (CEQ, NAS, EPA, and NOAA) that (1) no leasing be allowed in the Gulf of Alaska at this time and (2) that the Department defer decisions on leasing until completion of necessary environmental baseline studies. In sum, there seems little "interdiscipline" in the Department's disregard of the recommendations of the federal agencies charged with protection of, or research into environmental protection.

Sec. 102(B) of NEPA requires the Department of Interior to "identify and develop methods and procedures...which will insure that presently unquantified environmental amenities and values may be given appropriate consideration in decision-making along with economic and technical considerations."

This language mirrors in large respect the comment made by NOAA, that there was a need to quantify the environmental risks of drilling in the Gulf of Alaska before an informed decision on leasing in that region could be made. Not only has the Department not adopted any criteria by which those quantified risks and values could be assessed against resource potential and other relevant considerations, but, moreover, the Department has stated that it will make its decision on leasing in the region before any of the necessary data is available.

Secs. 102 (C) and (D) of NEPA will be discussed with reference to the impact statement itself.

In the case of Gulf Oil Company v. Morton, 6 ERC 1152 (CA9 1973), the Department of Interior successfully argued that the Outer Continental Shelf Lands Act imposed upon it the responsibility of conserving all the resources of the Outer Continental Shelf, and not merely the mineral resources. In the impact statement, and in the five-year planning schedule, the Department has done little to insure that other resources will be conserved. Again, the Department has indicated that it is willing to proceed in regions prior to an understanding of the impact of oil drilling upon those other resources. The Department has given no indication of a responsiveness to the particular values and vulnerabilities of the various OCS frontier areas.

The Endangered Species Act of 1973 was enacted "to provide a means whereby the eco-systems upon which endanged species and threatened species depend may be conserved, to provide a program for the conservation of such endangered species and threatened species, and to take such steps as may be appropriate to achieve the purposes of the treaties and conventions set forth in sebsection (a) of this section." (16 USC §1531(b)). To further that goal, Congress has required that "all federal departments and agencies shall seek to conserve endangered species and threatened species and shall utilize their authorities in furtherance of the purposes of the Chapter." (§1531(c)). The term "conserve" includes "the use of all methods and procedures which are necessary to bring any endangered species or threatened species to the point in which the measures provided pursuant to this chapter are no longer necessary". (§1532(2)).

The impact statement gives short shrift to the effect of Gulf of Alaska oil development on the plethora of endangered species which thrive in the Gulf. As noted previously, the Gulf of Alaska provides either a seasonal or permanent home for many species threatened with worldwide extinction. The value of the Gulf of Alaska as a haven for these beleaguered species is further noted in the CEQ report. Nonetheless, there is nothing said in the impact statement concerning methods that will be used in administering the OCS leasing program to effectively protect these species and their habitats. The Department of Interior has displayed a willingness to proceed with drilling in the Gulf of Alaska despite the presence of a wide range of threatened and endangered species and despite a general ignorance as to the impacts of oil development on their future. In sum, the State would submit that the Department, in identifying the Gulf of Alaska for early oil and gas leasing, has not used "all methods and procedures which are necessary to bring any endangered species or threatened species to the point at which the measures provided pursuant to this chapter are no longer necessary", and is therefore, in violation of the Act.

Indeed, it is the general failure of the Department to address its divergent managerial roles in the Gulf of Alaska which raises serious questions as to the Department's compliance with existing laws. In addition to its responsibilities under the Endangered Species Act, the Department currently manages numerous federal land withdrawals designed to protect ecological and scenic qualities within the State of Alaska. Many of these withdrawals are within the coastal zone. Moreover the Department has proposed the additional withdrawal of 83,000,000 acres for classification into the "Four Systems." The Department eludes to the values of these withdawals:

"All existing and proposed Alaska coastal wildlife refuges should be considered unique environments as that was the very reason they were designated as such." (Vol. 1, pg. 554)

On page 123, Vol 2, the Department concedes that "the main attraction to Alaska visitors is the undeveloped wild and rugged wilderness this region possesses." The Department has been entrusted with responsibilities over the management of its wildlife refuges and other withdrawals in the Alaska area. To subject the ecological and scenic values of the withdrawals to the massive threats of substantial offshore oil development from outside their boundaries, raises grave questions as to whether the Department is indeed discharging its public trust responsibilities over these lands. In the final impact statement, the Department should candidly and comprehensively address the potential conflicts between the federal withdrawals existing and proposed in Alaska, and adjacent offshore oil development. The Department should specifically address the potential impacts of oil development on existing wildlife refuges, parks, and monuments, on endangered species, and on the Department's responsibilities under all federal program in which it is presently involved.

D. Section by Section Analysis of DES 74-90.

SECTION ONE

Overview criticism of Sec. 1 are provided in section 2 of these comments, relating to the scope of the impact statement. Specific comments include:

Page 9. The impact statement discusses the Department's response to drilling opposition in the so-called "MAFLA" area. It states that substantial environmental baseline data gathering was undertaken in response to local opposition. The impact statement should also indicate that the lease was held well before receipt and analysis of any meaninful baseline data. 49/

Page 11. The impact statement states that "BLM and USGS are exploring various options whose intent would be to require early release of geological and geophysical information in areas designated for lease sales." Numerous criticisms have been given of the current lack of geophysical and geological data which is available to BLM, and the public, early enough in the decision-making process to be of substantial benefit in undertaking NEPA review. 50/ The impact statement should make specific recommentdations or determinations of policy which would enable the reviewing public to assess the adequacy of the manner in which the program will be administered. The statement should say more than that responsible Federal agencies are "exploring" various matters. Statements like these give the public no indication of the adequacy of the managerial aspects of the program.

49/ See "Florida, Its Outer Continental Shelf and Project Independence: Is the Prize Worth the Gamble," Dr. James I. Jones, Florida Division of State Planning

50/ "OCS and the Coastal Zone," at 20-25.

Page 12

The bonus bidding system has also been critized as compelling hasty development and precluding the option of subsequent termination of leases or substantial modifications of acceptable operational activities because of subsequently received adverse environmental data. 51/ These criticism should be noted and responded to in the final impact statement.

Pages 12-13

According to the statement, BLM and USGS have been able to "keep pace somewhat" with staffing needs in minerals management. A more detailed response is called for in light of the substantial criticism leveled by the General Accounting Office on the lack of well-trained inspectors and supervisors within USGS. 52/ The statement should specifically state how many inspectors and other supervisors are planned for each frontier OCS region.

Pages 19-28

The State would like to make several comments regarding the Department of Interior's "two-tiered" decision-making system. We have noted previously the difficulties the State encounters in responding to early calls for nominations which ask for environmental information on specific areas. To respond to a call for nominations prior to the receipt of environmental information could be premature, and perhaps,

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51/ "OCS SoCal Hearings," at 40.

52/ "Improved Inspection and Regulation Could Reduce the Possibility of Oil Spills on the Outer Continental Shelf," Report to the Conservation and Natural Resources Subcommittee, Committee on Government Operations, House of Representatives, (Hereinafter "GAO Report").

inaccurate. Oil industry responses, however, are based on substantial geophysical and geological data not shared with the general public either before or after the call. The same problems are applicable to the two-tier system. The results of the February 20, 1974 "poll" were predictable. Industry's responses are presumably informed and specific, based on significant amounts of seismic and other geophysical data on the various areas involved. The environmental rankings, on the other hand, simply could not be made because information was not available. Thus, the rankings, by necessity, become primarily those of industry. These rankings have since been mirrored in the five-year planning schedule, to a large degree. Therefore, as with calls for nominations, the State, and the reviewing public in general, may find themselves in a position of merely reacting to what is essentially an industry proposal. In sum, the first tier of the decision-making system--that is, the overall environmental ranking--should not be held until information is available to intelligently make such rankings. It is true that calls for nominations do not bind the Department to lease the nominated areas; but the State would appreciate the opportunity to comment both on the calls for nominations and nationwide rankings. We would ask that this option be left open until environmental information gathering efforts are completed in all frontier areas and that no action be taken on either the calls or on the five-year leasing schedule until that information is gathered and analyzed.

Pages 22-23

With reference to our discussion on the probably PAD V energy surplus, we would recommend that the following statement be omitted as inaccurate and overly general:

1. "In the present day tight petroleum supply situation, markets for petroleum are characterized by greater demand than supply."

2. "Alaska production would probably be processed in the Pacific seaboard for consumption in Pacific and western states."

<u>Page 24</u>

The impact statement states that the CEQ report is now being "reviewed in detail." This is a convenient way of escaping the massive amount of information contained in the report adverse to the Department's program. However, this statement does little to acquaint the public with the serious questions raised by the report. The statement should be omitted, and in its place, a detailed analysis of each CEQ recommendation and finding, along with the Department's response and implementing actions.

<u>Page 27</u>.

The impact statement states that contemporaneous with a call for nominations, "resources reports of various government agencies" are requested. The impact statement should indicate that these "government agencies" are at the federal level. At the NOPS hearings, state officials from California criticized the Department of Interior for its failure to consult them prior to the call for nominations. 53/ A similar pattern has unfolded in the State of Alaska.

53/ "OCS SoCal Hearings," at 3.

Pages 29-86

A major criticism of Section 1.C is the lack of information on the safety record of existing OCS oil and gas development. Specific comments on this section point out areas where more data are neeeded.

As the statement admits, most of the information in the section is applicable to the Gulf of Mexico since the bulk of U.S. OCS experience is there. It would be useful to include more references to equipment and experience in North Sea work where operating conditions are worse than those conditions normal to the Gulf of Mexico. 54/ Data included in the Council on Environmental Qualifty study indicates that sustained wind speed and maximum significant wave height are similar in the North Sea and Gulf of Alaska. 55/

Page 31

The EIS discusses exploratory drilling. No mention is made of the fact that this is one of the most dangerous phases of offshore oil production because of the possibility of a blowout. The CEQ Report discusses this possibility as well as potential hazards from drill mud and cuttings discharges. 56/

Page 34

The EIS states that it is expected that risers can be designed for use in 3000 feet of water. What is maximum depth in use now?

54/ "Despite industry's assurance that the great cost of these platforms requires that they be designed for the most extreme envirnental conditions and that they be operated only under design conditions, drilling platforms have been lost in the North Sea, some quite recently." CEQ Report, 8-7--8-8

55/ CEQ Report at 5-3

56/ Ibid., p. 4-4.

Page 35

The EIS states "Blowout preventers have been developed for installation on the sea floor." Where are they being used now? What is their depth limitations, if any, and what are their advantages/disadvantages.

The EIS states that failure to comply with USGS and USCG regulations can result in suspension of rig activity until corrections are completed. The GAO stated that not only is inspection of drilling and producing rigs inadequate and nonuniform 57/ but also that violations requiring shutins do not always result in shutin until correction is accomplished. 58/ In addition, the CEQ Report noted that industry's response to shutins is to stockpile parts to correct the violations but has not improved the incidence of violation. It was recommended that punative shutins would be more effective in deterring violations. 59/

Pages 39-40

The EIS states, "buoyant towers for production have potential applications in water deeper than 1000 feet." How are the towers kept in place? Have any bouyant towers been used anywhere and, if so, at what depth? The CEQ report points out that buoyant towers are susceptible to damage by tsunamis in the Gulf of Alaska. 60/

57/ GAO Report at 3, 18

58/ Ibid., p. 14

59/ CEQ Report at 9-21

60/ Ibid., P. 5-9

Page 41

The EIS states precautions to overcome ice crashing and abrasion are necessary in the Arctic. In addition to floating ice, icing on the structure itself could be severe in the Gulf of Alaska. 61/

The EIS states "In the Gulf of Alaska and Pacific areas, seismic activity is of major concern. Techniques used to design large office buildings have been expanded to apply to offshore structures." For such a "major concern," this is a totally inadequate discussion. As the CEQ Report points out, no platform to date has been designed for the magnitute of earthquakes which can be experienced in the Gulf of Alaska (Richter scale 8.3-8.6). 62/

Page 46

The EIS states that blowout preventers and other well control equipment is tested on a schedule set by "prudent practice, but not less often than regulations specify." This section should be more specific about how often these devices should be tested.

Page 50

Subsea completions are discussed. It should be noted that the CEQ Report recommends that subsea completion equipment be used in new areas where it would provide a higher degree of environmental protection and reduce conflicts with competing uses of the OCS. 64/ The statement should explore those areas in the Gulf of Alaska where conflicting uses, such as fishing and tanker traffic, would conflict with above water structures.

61/ Ibid., p 5-5

62/ Ibid., p 1-26

63/ Ibid., p. 4-24

64/ Ibid., p. 1-26

Page 53

The EIS discusses treatment of produced water containing oil. The section does not mention the quantity of oil which may remain in the water after treatment. In the Gulf of Mexico, the treated produced water can contain up to 100 ppm of oil and 50 ppm average. 65/ Proposed U.S. Environmental Protection Agency New Source Performance Standards for Oil Exploration and Production require that produced water shall not be discharged into U.S. waters, requiring, in effect, reinjection below ground into a suitable formation. 66/

Page 54

The EIS states, "Safety records during well workovers are excellent." How many accidents have there been, how much oil was lost and what was the cause of accidents during well workovers? Despite the supposed good record, the USGS is considering prohibiting simultaneous well workover and production in the Gulf of Mexico by revision of the OCS orders. If the simultaneous workover and production is so dangerous as to be prohibited in the OCS Orders for the Gulf of Mexico, why is it not prohibited in the proposed OCS Orders for the Gulf of Alaska? 67/

Page 58

The EIS discusses gathering lines and pipelines to shore to transport oil. The entire discussion ignores the devastating impact the pipe-laying may have in wetlands where trenches of varying widths (8-50 feet) are dredged. The resulting canals can accerlerate erosion, disturb drainage patterns and destroy very biologically productive areas. 68/

66/ U.S. Environmental Protection Agency, Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Catagory, October 1974, p. II-4.

67/ U.S. Geological Survey, "Proposed OCS Orders for the Gulf of Alaska," August 1, 1974, p. 8-29.

68/ Council on Environmental Quality, Op. Cit., p. 4-19

Areas of the Louisiana coast have been particularly disturbed by pipe-laying. 69/ It is estimated that up to eight acres of wetlands may be destroyed for each one mile of pipeline laid. 70/

This section also does not discuss coordinating the location of pipelines to minimize the number of coastal locations which must be disturbed. The House Conservation and Natural Resources Subcommittee found that a multitude of Federal agencies issue permits for and regulate the location and safety of pipelines from the OCS, including the USGS, BLM, FPC, Corps of Engineers and DOT's Office of Pipeline Safety. As late as 1974 the USGS and the DOT/OPS had not come to an agreement over regulating pipeline safety and the Corps of Engineers and Department of Interior had come to no agreement over who is responsible for reviewing pipeline environmental impact. 71/

Page 67

The EIS states "With the volume of air and water-borne traffic in the Gulf of Mexic, pipeline leaks are unlikely to go undetected for any appreciable length of time." This is not necessarily true of the Gulf of Alaska. Proposed USGS OCS operating orders for Gulf of Alaska (No. 9) requires visual pipeline inspection once a month. 72/ The draft EIS (page 66) talks about a minimum patrolling frequency of once every two weeks. This conflict should be resolved in favor of more frequent patrolling if air and waterborne traffic is not sufficient to provide frequent incidental inspection. Adverse weather in the Gulf of Alaska will also inhibit adequate visual inspection.

69/ "Our Threatened Environment" at 47.

70/ NOPS Hearings at 203. Pipelines are a major source of chronic pollution, and current pipeline technology is inadequate in the Gulf of Alaska." "OCS and the Coastal Zone" at 90.

71/ "Our Threatened Environment" at p. 50.

72/ U.S. Geological Survey, Op. Cit., p. 9-22.

Page 76

The EIS states "there is very little offshore oil storage on the U.S. OCS, and no need or requirement is foreseen for new areas." This is in direct contradiction to the CEQ report which feels that tankers may be used in early states of field production, implying that offshore storage will be needed. 73/ The CEQ Report goes on to discuss the present design and the hazards to offshore storage from natural events. 74/ 75/ Either the Draft Environmental Statement should justify its assertion that offshore storage will not be required, or the hazards of such storage should be thoroughly discussed.

Page 77

Oil spill prevention facilities used during production and work-over are discussed. From Cook Inlet experience, malfunctioning level controls on skim tanks cause many spills, This problem is not mentioned and there are no data on other failures of safety features. Data contained in the CEQ Report reflect the Cook Inlet experience. The report notes that in 1971 and 1972, there were 2869 spills of less than 100 barrels (4200 gallons) from platforms. 76/

Pages 85-86

No new technology is anticipated in the oil spill containment and clean-up field. This is a particularly dismal prospect for the Gulf of Alaska. Existing spill containment and clean-up equipment cannot operate in more than 5-10 foot seas, 20 knot winds and 1-2 knots

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73/ CEQ REport at 8-18

74/ Ibid., p. 5-11, 5-13.

75/ Ibid., p. 8-20

76/ Ibid., p. 4-29

currents. 77/ 78/ There is no discussion of specific equipment capable of operating on the high seas; nor is there any discussion of the logistics of fighting a spill on the Gulf of Alaska coast.

Page 89

The EIS state:

> "The Secretary of the Interior may withdraw tracts from the sale, delay the sale, or pose special stipulations on operators in tracts located near highly valued sites or problem areas."

In the first instance, it should be noted that the lease sale for the Gulf of Alaksa is planned long before receipt and analysis of environmental information necessary to establish where the "highly valued sites or....problem areas" are in the Gulf of Alaska. Beyond that, the impact statement would be aided by a discussion outlining the criteria which the Department of Interior will use in withdrawing tracts from sale, along with analysis of the Department's past record in withdrawing these tracts for particular reasons. Specifically, how many tracts have previously been withdrawn from sales in the past, and for what reasons?

Page 91-92

In the discussion of the selection of the bidding system, the Department of Interior should be more complete and more definitive. As noted previously, use of the bonus bidding system tends to "lock in" the acquired tract for development, due simply to the large initial investment made. Use of a royality system, or, better, a license

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77/ Glaeser, John L., "An Effective Oil Spill Containment-Recovery System for High Seas Use," Proceedings of Joint Conference on Prevention and Control of Oil Spills, March 13-15, 1973, Washington, D.C., EPA, USCG, API, p. 589, ff.

78/ CEQ Report at 4-23.

system, would give the Department substantially increased flexibility in later withdrawing tracts which subsequently-received environmental information determines to be hazardous or within particularly sensitive areas.

Page 96

The State is greatly concerned over the statement in the EIS that "these (OCS operating) regulations (for the Gulf of Mexico) will be applied, probably with no change, to other geographic areas."

The regulations, orders and performance standards which govern exploratory and production operation in the Gulf of Alaska, and other frontier areas, should be designed to address specific problems involved in these new regions.

Page 97

It is stated that "the operators are required to report all spills or leakage of oil to USGS without delay." The U.S. Coast Guard has observed about 1,000 small spills offshore each year in the Louisiana Outer Continental Shelf. 79/ There has been some question as to whether all these spills have been reported. The impact statement should discuss the degree of compliance of industry with the reporting requirement.

The impact statement, on page 97, discusses briefly OCS order #8, which allows production water discharges containing up to 100 parts per million oil residue to be discharged into the ocean. This needs to be amplified, with the discussion of potential impacts of these "planned discharges" in the navigable waters. The significance of these discharges, particularly as the production formation ages, should be amplified. For example, the CEQ reports stated:

79/ NOPS Hearings at 226.

"As much as 50 parts per million of oil, primarily soluable components, may be continously discharged from each platform oil-water separator unit. A local plume is formed and the sub-surface contaminated. Based on MIT's conservative assumptions in the Georgia Bank study, a single central separator platform (processing 200,000 barrels per day) releases separator effluent at a constant rate of 3 cubic feet per second. At a maximum oil concentration of 50 parts per million effluent, such a platform may discharge somewhat less than 1,000 barrels of separator oil per year." 80/

As has been stressed throughout these comments, the effects of chronic, low-level pollution on marine biota of the affected areas is not well understood, and may, in the long run, be catastrophic. The 50 parts per million average has been criticized as being "comp-pletely arbitary, having been set with an eye towards OCS equipment capability rather than towards a desirable environmental standard." 81/ The CEQ report recommends that in "undeveloped areas like the Altantic and the Gulf of Alaska OCS, discretion dictates that environmental loadings of oil and other materials be kept at the lowest levels possible at least until baseline studies such as those recently initiated by the Bureau of Land Management determine the environmental risk from such materials." 82/ In sum, the impact statement should not treat as immutable this level of intentional discharge.

80/ CEQ Report at 6-41

81/ Id at 8-13.

82/ Id.

The EIS states that "draft operating orders for Alaskan operations have been developed and are currently being reviewed by industry. The Department of Interior will not hold lease sale in frontier areas until operating orders are developed for these areas." As have been noted previously, USGS previously promised the House Government Operations Committee it would no longer prepare OCS orders in consultation with industry prior to release to the public. The practice of industry consultation has been severely critized by a variety of sectors. The University of Oklahoma report noted:

> "Most of these weaknesses in physical technology exist because, until very recently, standards used for determining the adequacy of the technologies have been based largely on industry judgement of what was economically feasible...The most detailed rules, OCS orders issued for each USGS area, have been and are the product of an institutionalized process of government and industry cooperation. Perhaps as a consequence, government regulation had tended to be heavily dependent upon industry's engineering and operational expertise when establishing OCS regulations.
>
> "USGS should appoint an independent representative board of experts which should periodically review the state-of-the-art OCS technology and make recommendations concerning desirable changes, particularly changes in equipment and performance requirements and standards...
>
> "USGS should appoint an advisory committee to assist its Area Supervisors in drafting and revising OCS orders. This committee should include representatives of parties of interest in addition to industry in order to broaden participation beyond the present pattern of government-industry cooperation." 83/

83/ OCS and the Coastal Zone at 168-169.

On page 99, the statement suggests that OCS order #8 is being studied for "possible amendment to prohibit concurrent production and workover on the same platform." As noted previously, on pages 53 to 54, the statement says that USGS is revising order #8 to prohibit simultaneous operations. However, as these comments have also pointed out, both of these contradictory statements are inaccurate as to the Gulf of Alaska, where simultaneous operation are permitted under Draft Order #8.

Pages 100-108

A great deal could be said of BLM's and USGS' entire system of inspection and enforcement. On page 100 to 101, the EIS states that increased enforcement has increased operator compliance." However, on page 107, the statement admits there is no evidence to support this assertion, and, on pages 104 through 105, it is noted that the percentage of equipment failure has not changed between 1971 and 1973. More recent and definitive data is needed. Some of the more severe criticisms of the General Accounting Office on the USGS enforcement program should be noted in this section of the statement, along with specific measures which USGS has instituted to improve their enforcement capabilities.

The GAO report stated that inspections in the Gulf of Mexico had not occurred at the frequency specified in the regulations, a conclusion borne out by tables 3 through 5 (pages 104 and 195), which show a sharp decline in inspections during 1973. In addition, USGS has been criticized for having no formal training program for inspectors and engineers. 84/

84/ See GAO Report, at 2-3.

The impact statement does not specifically address the manner in which these shortcomings have been corrected. Other findings noted by the GAO report include:

1. "Survey officials informed GAO that, since inception of the lease program, no leases have been canceled and and fines have been levied only once in 1970 when nine oil companies were fined $2.4 million for failure to install required safety devices." 85/
2. GAO observed that certain inspectors in the Gulf Coast region did not always follow prescribed enforcement procedures, recommending that USGS "emphasize the need for inspection personnel in the Gulf coast region to apply prescribed enforcement actions for violation of OCS orders unless deviations are authorized under circumstances specified by the region and properly documented in each case." 86/
3. "Reexamine the Pacific region policy of not halting operatives for violations of OCS orders and consider the advisability of shutting down individual wells to encourage the operator to promptly correct deficiencies." 87/

The House Committee on Government Operation emphasized the traditional laxity of inspection and enforcement programs of USGS:

> "While accompaning survey inspectors on eight inspection trips of 16 structures in the Gulf of Mexico, we noted that they did not follow prescribed enforcement actions for violation of OCS

85/ Id at 2

86/ Id at 4

87/ Id

orders on 5 of the 16 structures. These violations related to required safety procedures and/or equipment. For example, on one inspection, the Survey technician noted that deck drains used to collect contaminents were not piped to a tank designed to prevent discharge of oil into the water. In this instance, the inspector orally warned the operator, although the prescribed enforcement action called for suspending operations until the deficiency was corrected." 88/

The same committee also noted serious problems in logistics in carrying out inspection programs. It noted that, in the Gulf of Mexico, oil companies had refused to allow USGS-contracted helicopters to land on oil company platforms for necessary refueling during inspection trips. The committee further noted USGS reluctance to press the oil companies into providing this critical logistical support.

Existing inspection and enforcement mechanisms are inadequate. By accelerating the Outer Continental Shelf leasing program, responsible authorities have raised serious doubts as to whether or not a further strain on manpower and necessary support will not further aggravate the effectiveness of USGS procedures. The National Ocean Policy Study states:

88/ "Our Threatened Environment" at 64. The committee also found that USGS was unwilling to make violations of OCS orders and operating standards public;

> "Survey officials believed that it was more important for the public to be aware of how effectively the OCS program was being carried out rather than publicly disclosing the individual notices of noncompliance which contained technical information, and therefore would not be of interest to the public." Id. at 67.

Unfortunately, this element of covering up industry failures has been carried over into the drafting of DES 74-90.

"There is evidence that regulation of environmental and safety practices in OCS oil and gas operations is inadequate. The U.S. Geological Survey of the Department of the Interior has primary responsibility for issuing and enforcing orders which govern oil company practices. Two recent studies found that the USGS did not enforce these orders to the fullest extent, but often issued oral warnings of violations when written notices or fines were called for. In addition, the orders themselves appear to need strengthening. The USGS has permitted the industry being regulated to comment on proposed regulations prior to their publication in the Federal Register for public comment. The Subcommittee on Conservation and Natural Resources of the House of Representatives' Government Operations Committee has contended that the practice of circulating proposed orders to the industry's Offshore Operators Committee is a violation of the Administration Procedure Act and 'not in the public interest', since the strength of the orders may be compromised.

"In view of these shortcomings, there is cause for concern about the ability of the U.S. Geological Survey to effectively regulate the vast acreage contemplated for leasing in 1975." 90/

The environmental impact statement should specifically address these serious concerns, with more than a sentence or two of reassurance. Specifically, the statement should provide:

i. Specific mechanisms which are or will be adopted in respond to criticisms of the General Accounting Office report.

89/ Id at 58-62.

90/ OCS and the Coastal Zone at 2-3.

2. The number of inspectors and technicians, and the amount of financial and logistical support, that will be given to each OCS region.

3. Specific recommendations for strengthening the enforcement provisions of the Outer Continental Shelf Lands Act, creati strict liability for violations of OCS orders, and substantially increasing fines from the nominal $2,000.

Page 115

The impact statement states that, "the OPS (Office of Pipeline Safety) has general responsibilities for pipelines. It primarily supervises gas pipeline safety, including the establishment of design criteria directed toward increased safety." That statement passes over a serious jurisdictional dispute between BLM and OPS, which critics believe have resulted in inadequate, and even nonexistent, pipeline surveillance and oversight. The House Committee on Government Operations noted:

> "The committee understands that while this jurisdictional dispute is unresolved neither the Survey, the BLM or the OPS has been inspecting or regulating the pipelines. Every day of delay performing such inspections and promulgating such regulations increases the possibility of other serious pipeline breaks which might be prevented if either the USGS or the OPS monitored and inspected the pipelines." 91/

Apparently, resolution of the dispute between USGS and OPS hinged on a long-awaited legal opinion from the former's Solicitor's Office. The lengthy delays in resolving this dispute were noted by the committee:

> "It is incredible that a matter as important as the development of safety standards for, and the inspection of, OCS

91/ "Our Threatened Environment" at 54.

pipelines could be stalled for over a year because the Solicitor's Office has failed to render a needed 'legal opinion' on the Survey's jurisdiction." 92/

The impact statement should note what progress has been made in resolving this dispute, and should provide a discussion of the substance and scope of whatever pipeline safety regulations have been issued, both as they relate to offshore monitoring, and near shore and onshore impacts.

Pages 115 - 124

This section of the impact statement contains many references to federal-state coordination, specifically the Coastal Zone Management Act of 1972. The State will defer comments on the role of the Coastal Zone Management Act in the OCS program until discussion of Section 8 (D) (1) (c) of the impact statement.

Page 128

The EIS states:

The conclusion of the CEQ Report is that OCS development could be conducted in the Altantic and Gulf of Alaska, but only if CEQ recommendations and stipulations are accepted."

The presence of this statement in the impact statement is unfortunate. An accurate characterization of the CEQ Report is imperative.

Page 128 - 141

The role of environmental baseline and special studies in the OCS leasing program has been treated earlier in these comments.

92/ As noted previously, pipelines are a major source of chronic oil pollution. It is not implausible that the serious nature of chronic pipeline discharges is due in no small part to lack of regulation and inspection.

Page 144- 172

The discussion of the "Relationship of OCS Oil and Gas Leasing to U.S. Energy Supply" has been treated previously in these comments. This section, combined with Section 8 (f) on energy alternatives, as noted previously, is inadequate in its failure to relate alternative energy sources, OCS timing, and energy conservation into any sort of coherent decisional analysis on the need for the expanded OCS development.

This section, along with the section on energy alternatives, should deal at some length with potential production from increases in secondary and tertiary recovery operations. Advances in technology and the rise in fuel prices, increase potential usage of secondary and tertiary techniques. Increased use of secondary and tertiary recovery technique creates fewer environmental hazards than a great and hasty expansion of Outer Continental Shelf oil and gas leasing, and therefore the production potential of increased usage of these methods should be specifically stated.

SECTION 2

Page 463

The EIS states that the Gulf of Alaska-Aleutian Island-Arctic area is prone to frequent and severe earthquakes. During the last seventy years, eight seismic events had recorded magnitutes that equaled or exceeded a Richter 8 in that region.

A better understanding of the hazards that Gulf of Alaska evelopment will face, both from earthquakes and tsunamis, can be better provided by a discussion of the CEQ findings as to the expected frequency of Richter 7 and 8 earthquakes. In addition, the CEQ findings of the effects of these earthquakes on OCS structures should be noted.

Page 499

The impact statement acknowledges that weather conditions in the Gulf of Alaska will result in chronically poor visability conditions These conditions should be related to such critical aspects of OCS management as pipeline surveillance, on-site platform inspections and navigability.

Page 538

The EIS makes reference to the tanner and dungeness crab being caught in the Northeast Pacific. This table should be updated to at least 1972. INPFC documents and Pacific Marine Fisheries Commission documents should be used as reference sources.

Page 549-541

In the discussion of Bering Sea fisheries no mention is made of the shellfish fishery resources.

Pages 554-555

In the discussion of unique environments, the last paragraph should be expanded to include shellfish spawing areas. This reflects a major deficiency in ecological analysis--that is, the overemphasis on "anadromous" streams at the expense of other biological communities. There are many coastal areas, such as Clam Gulch on the Kenai Peninsula, which support large shellfish populations that are not within the confines of anadromous streams.

Pages 556-557

Included in this section should be a discussion of the hazards that tsunamis present in the Gulf of Alaska. Adequate documentation in this regard can be found in the CEQ report. In the statement's brief discussion of ice conditions, a candid admission that the oil industry does not currently possess technology sufficient to operate in significant ice areas should be provided.

Volume II

Page 113

With respect to the "six biological regions" of Alaska illustrated on page 113, the idea of the overall classification of region 6 and region 5, is satisfactory; however, the breakdown for the Gulf of Alaska and the Aleutians is too generalized. The outer coast from Queen Charlotte Island to Unimak Pass must be considered as a continuum; the internal waters of Southeastern Alaska can be considered as an estuary fjord coast unit; Prince William Sound, shorewards to Hinchinbrook-Montague Islands, can be considered as a protected marine fjord coast unit; the Cook Inlet area, shorewards from Cape Elizabeth-Baron Island-Cape Douglas can be considered as a complex transitionary estuary in which the importance of winter ice is a major environmental factor. Biologically, for OCS lease planning and management purposes, the Lower Cook Inlet region must be considered as an integral part of the inner-shelf environment of the open coast. This classification should be extensively amended to reflect realistic ecological relationships. The insular portion of the shelf surrounding the Aleution Islands, westward of Unimak Pass should also be looked at as a single ecological unit.

Page 123

In the paragraph concerning hunting there is no mention made of moose populations. There is also no mention made of the large elk herds in the Kodiak area although they do specifically point out Sitka black-tailed deer in the Prince William Sound area. There is no mention made of the fur bearing animals that are trapped for recreation and commercial uses. This paragraph should be expanded.

Page 121-152

The statement's treatment of present socio-economic conditions gives neither an adequate nor an accurate picture of the capacity of onshore areas to absorb OCS-induced development. BLM's analysis of land, transportation networks, economics and community infrastructure are all in need of substantial revision. Furthermore there is no discussion of the relationship between OCS development with BLM's proposals for energy corridors over native village land under ANCSA, although the corridor system would severely affect patterns of land use in Alaska.

Page 122

Knowledge of the availability and location of suitable land for onshore needs are of primary importance in predicting the scope and pattern of the socio-economic and environmental impacts of OCS development. However, BLM's 1,200+-page report treats Alaska's land tenure situation in one paragraph. This provides an indication of the inadequacy of this portion of the draft EIS document.

The statement simply notes that, due to the land selection provisions of the Alaska Native Claims Settlement Act (ANCSA) and the Alaska Statehood Act, "...the ownership of long stretches of coastline may be in doubt." However, in equally long stretches of coastline, the ownership of land and the restrictions of its use are well established. The impact statement should systematically indicate what lands are available for and suited to specific uses, what lands are presently withdrawn under ANCSA and the pattern of land tenure in relation to oil development needs in each OCS subregion.

Finally, no effort is made to analyze locational factors as they relate to the availability of land for OCS-related developments. Such conditions as steep slopes, glaciation, shallow water, permafrost and a variety of other soil and topographic constraints will very definitely affect the feasibility of developing onshore support services, pipeline landfalls, port facilities, and so on.

The statement must provide an indication of these locational, tenure and environmental factors as they relate to each of Alaska's seven OCS regions to make a meaningful interpretation of the socio-economic impacts of OCS leasing and development possible.

<u>Page 129-132</u>

The EIS states that the impact on ports and shipping is likely to be significant and then fails to provide any information on the overall pattern and capacity of water transportation in Alaska and in relation to Alaska's seven OCS subregions. The treatment of port facilities is inadequate. There is no discussion of location of ports, their capacity to handle increased traffic or even their actual present industrial capacities. Of the eight major harbors listed in Table 69, page 131, only two are located within usable distance from an OCS region. Of Alaska's eight OCS regions, six have no convenient access to the major ports listed. There is, in short, no consideration of the relationship bwtween port location, capacity and the foreseeable demands of OCS development in BLM's analysis.

A review of 1973 tonnages handled by the "major" ports in each OCS subregion indicates the inadequacy of present facilities to handle the large demands of OCS development:

93/ Waterborne Commerce of the U.S., Corps of Engineers, Department of the Army, Washington, D.C., annual reports, 1971 and 1973.

OCS Region	Port	July 1, 1973 Population	1973 Tonnage	
Gulf of Alaska	Cordova	2,114	46,750	
	Kodiak	3,859	236,612	(42% fisheries products)
	Seward	1,587	51,913	
	Valdez	1,106	301,076	(98% petroleum products for transshipment)
	Whittier	116	392,491	(app. 99% transshipment to Anchorage)
Lower Cook Inlet	Homer	1,243	146,349	(76% rafted logs)
	Seldovia	437	10,663	
Aleutian Shelf	King Cove	283	12,682	
	Old Harbor	327	3,166	
	Unalaska	510	163,586	(68% distillate fuels for transshipment)
	Remainder, South Side, Alaska Pen. and Aleutians		11,864,646	(85% petroleum product exports from Kenai/Cook Inlet area)
Bristol Bay	No ports listed			
Bering Sea	Bethel	2,921	41,860	
	Dillingham	999	6,248	
	Naknek River	1,147 (BB Borough)	5,169	
	Nome	2,427	28,782	
Chukchi Sea	No ports listed			
Beaufort Sea	No ports listed			

There are, then, no deep-water facilities in northern and western Alaska (the Bering Sea, Chukchi Sea and Beaufort Sea areas). At present, ocean-going supply vessels must anchor from 1 mile to 15 miles offshore, transferring their cargo to shallow draft craft to be lightered ashore.

Also, the superficial analysis of port tonnages gives a poor picture of present capability. The very high proportion of tonnage figures for Southeast Alaska ports given by BLM is due mainly to the large volumes of rafted logs produced by extensive logging operations in the Tongass National Forest. Log-rafting, however, demands minimal port and harbor facilities. Large volumes of rafted logs can be produced from an onshore site with no permanent harbor improvements. These figures, then, do not accurately reflect the potential heavy industrial use of any of Alaska's ports. As a further comment, the very large tonnage shown for the southern side of the Alaska Peninsula and the Aleutians (which accounts for roughly 50 percent of the State's total tonnage) consists almost exclusively (estimated at 98 percent) of oil and petrochemical products from Upper Cook Inlet which are imported from and exported to both foreign and domestic ports from one location--Kenai. As much of this tonnage is loaded by pipe, there are, again, very limited port and harbor facilities suitable for industrial development.

It is essential for the statement to develop a more adequate picture of present port and harbor locations and capacities, so potential impacts can be accurately prediceted. Onshore impacts can then be accommodated with the least delay to OCS development and with the least disruptive effects on the regional and national economies.

Page 133-134

The EIS seems to have missed the point in its consideration of the role of air transportation in Alaska. BLM suggests, because the overall costs of air transportation are higher than other transportation modes, the historic dependence on air transportation in Alaska will tend to decrease as other transportation modes develop.

However, becuase of the massive capital costs in return for the rather low-level of actual returns, other transportation modes are not likely to be developed. For example, the exploration and development of the massive Prudhoe Bay field relied heavily on air transportation to move equipment and material as no alternative year-round transportation mode was available. The construction of an approximately 400-mile-long road from Fairbanks to Prudhoe Bay became economically feasible only in conjunction with a trans-Alaska pipeline.

Because of the importance of air transportation in any major industrial development in Alaska, it is essential for the statement to provide an accurate picture of the present capacity of air transportation facilities and services in each of Alaska's seven OCS regions and in the larger metropolitan areas which will help support OCS development. Such an assessment would include runway locations, lengths, surfacing, load and aircraft type limitations, availability and extent of fuel, maintenance and support services.

Page 134

BLM's discussion of rail service does not provide an accurate impression of the relationship of rail transportation to OCS development.

Although the statement mentions that Alaska is served by two railroads, it does not point out that rail services will be of almost no use in meeting OCS-induced needs. These railroads have neither any connection to each other, nor to any other railline anywhere in North America. Further, only one of Alaska's seven OCS regions has direct rail service and, even here, only two ports have rail connections.

This lack of rail service must be made clear and incorporated in later analysis of the impacts of OCS development on transporation systems and the costs of improvements in Alaska.

Page 135

Again, the importance of the very limited development of surface transportation in Alaska is not made clear. Only one OCS area is served by a road system interconnected to other portions of the State. Six OCS subregions, then, have no public highway connections to Alaska's major population centers or even among the communities with each subregion.

The point that BLM must make obvious is that, without massive Federal and State expenditures for highway construction, OCS development in all areas of Alaska, except the Gulf, will depend upon air and water networks. Mentioned earlier was the lack of integration of the EIS with BLM's proposed energy corridor system over village selections under ANCSA.

These suggestions on expanding the analysis of various transportation modes will provide information necessary to judge the actual costs, and the timing and development constraints on OCS development. Taken as a whole, the lack of rail and surface transportation, the severe sea ice and weather problems in relation to water and air transportation and the limited port and airport facilities in Alaska have historically limited development in Alaska's coastal zone. Before any judgement of the actual economic and technical feasibility of rapid OCS development is made, these transportation constraints must be analyzed and incorporated into the EIS.

Pages 136-138

The discussion of Commercial Fisheries is too brief and generalized. This section does not give enough information to get the proper outlook or perspective on various fisheries of the State. The section should be updated, as the information is from 1971. Use of 1971 catch and values statistics is a very poor example, as it is known that coho,

pink and chum salmon are predominantly even-year fish and are in much greater abundance in even years than in odd years. Rather than using one year's data, the past 10-year average of production and current values of fisheries products should be used.

Page 143

The economic data provided by BLM is somewhat misleading. By discussing the value of various industrial activity in Alaska in product terms, the real structural importance of those economic sectors is blurred. While the petroleum industry may account for a 10 percent greater gross production than fisheries, fisheries-related employment (fishermen, canneries, other processing and transportation) mav range from 5-10 times greater than that of the petroleum industry. 94/

Because of its extremely small size, Alaska's economy is susceptible to large inflationary and structural changes resulting from large developments. Unless the inter-relationships of various aspects of the economy are understood, the prediction and avoidance of such impacts is not possible. Much additional work on the structure and sensitivity of Alaska's economy needs to be done by BLM before irreversible actions are taken.

Page 153-155

This section of the EIS entitled "Existing Environmental Quality Problems in Coastal Zone," deals extensively with water quality problems caused by coastal communities and commercial fishermen dumping raw sewage. It also devotes a paragraph to the seafood industry.

94/ Drawn from historical economic data provided by the Research and Analysis Section, Employment Security Division, Department of Labor, Juneau, Alaska.

"Some accommodation and adaptation can be expected to accrue over time. This can be inferred from the apparant health of the Gulf of Mexico's eco-system, where commercial fish catches of all types have either held steady or have increased over the last 25 years, with the total catch and catch per unit effort."

It should be noted that, although the number of shrimp boats operating in the Gulf of Mexico have doubled in the past several years, total shrimp catches in that area have not increased. 95/ The result--a significant decrease in per capita catches of shrimp. The oyster industry in the Gulf of Mexico has also suffered dramatically. Experts believe that the impacts on the oyster industry may have been due to the massive loss of wetlands in the Louisiana area. 96/ In any event, results in the Gulf of Mexico have practically no biological relevance to northern OCS areas.

Page 159

The statement list five general categories of effects of oil on organisms. Their list is garbled and incomplete. In a paper published by Max Blumer, Senior Scientist, Woods Hole Oceanographic Institution, Woods Hole, Massachusetts, "Oil Contamination and the Living Resources of the Sea" (presented at the hearings before the Committee on Interior and Insular Affairs, U.S. Senate, March 23, 1972), a more accurate and complete summarization is given.

95/ NOPS Hearings at 213.

96/ Id. at 203, Louisiana wetlands are being lost at a rate of 16.5 square miles per year. Id.

Oil company applications to EPA for National Pollutant Discharge Elimination System permits document that oil platforms are dumping raw sewage daily into Cook Inlet--this fact has been totally ignored in the EIS. Other major contributors to the degradation of Alaska's water quality are pulp, petrochemical and shipping activities.

Page 157

According to the EIS, "the most severe impact that can affect organisms and communities of marine and coastal eco-systems are those that result from spilled oil."

This is not necessarily true. Chronic low-level pollution resulting from intentional discharge can also have significant impact on marine and coastal eco-systems. Max Blumer, in his study "Scientific Aspects of the Oil Spill Problem" (Environmental Affairs, 1:1, April, 1971) asserts, "it is obvious that a very simple - and seemingly innocuous interference at extremely low concentration levels may have disastrous effects on the survival of any marine food chain." Evans and Rice (Fisheries Bulletin, Vol 72, pp. 625-638, 1974) also deal with the subject of chronic low-level pollution. In "The Alaskan Arctic Coast, A Background Study of Available Knowledge" chronic low-level pollution is discussed as a major impact of OCS development.

Page 158

The impact statement tells us "no geographic area would have 10 million acres offered in 1975 (at present there are 10 million acres leased in the Gulf of Mexico), so effects would be generally less than those observed in the Gulf of Mexico aside from catastrophic localized spills."

The number of acres leased cannot be equated with the severity of the impact. Alaska and other frontier areas will be more significantly affected than areas such as the Gulf of Mexico where development has been on-going for many years.

The State is distressed by the all too familiar "selling point" offered by the oil industry for offshore oil drilling:

The EIS states:

"Pipeline burial in submerged waters, and pipeline crossing on onland habitat is perhaps the second most severe impact producing aspect after oil spills. Pipeline burial produces effects similar to dredging activities...."

Indeed, dredging is necessary in onshore pipeline siting. For each mile of pipeline laid, 8 acres of wetland have been lost in the Gulf of Mexico. 97/ In addition, impact such as salt water intrusion, tributary and habitat loss have been occasioned on a massive scale in the Gulf of Mexico. Pipeline construction has been one element in the annual loss of 16.5 square miles of wetlands per year in Louisiana during offshore operations in that area.

<u>Pages 162-199</u>

The discussion of the impacts of hydrocarbons upon aquatic biota shows many inconsistencies and contradictions. The reading of this section indicates, for example, that authors such as St. Amant contradict themselves. For example, he states, on p. 168, "Chronic pollution from offshore production sites represents an unknown factor. Daily drips and loss of small amounts of oil or other chemicals overboard do not appear to generate ecological problems because of the relative immensity of the water column. Whether such sublethal pollution will eventually accumulate and cause environmental degradation is yet to be determined." His statement seems to be somewhat at variance with the statement of p. 196, "it is St. Amant's opinion based on his experience that there has been an decrease in overall productivity in Louisiana

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97/ Id.

resulting from introduction of crude oils into the ecosystems (St. Amant, 1973.)" His attitude appears to shift again on page 199: "St. Amant (1972) viewed chronic pollution as posing greater environmental jeopardy than the more obvious damage which results from accidental oil spill."

Page 162-163

The EIS states, "Impacts that may be anticipated to have an effect on plankton will result from accidental spills of oil and other toxic materials, discharge of drilling fluids and formation waters and burial of pipelines."

Chronic low-level pollution will also impact the plankton communities. This fact is brought out in the discussion of major impacts of petroleum exploitation in The Alaskan Arctic Coast, A Background Study of Available Knowledge, (Arctic Institute of North America, June, 1974). The special impacts of oil on under-ice producers are important in areas such as the Bering Sea, are inadequately considered (Cf: Burns & Morrow 1973).

Page 163

The EIS states: "After an oil spill has occured, that oil which has not evaporated, been carried ashore, or cleaned up will float at the surface for a time and eventually be dispersed as minute droplets in the water. In addition, certain components of crude oil are slightly soluble in water."

This is untrue. Max Blumer ("Oil Contamination and the Living Resources of the Sea," Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, March 23, 1972) explains:

"Because of their low density relative to sea water, crude oil and distillates should float; however, both the experiences of the 'Torrey Canyon' and the West Falmouth oil spill have shown oil on the sea floor. Oil in inshore and offshore sediments is not readily biodegraded; it can more with the sediments and can contaminate unpolluted areas long after an accident."

The MIT study "Potential Biological Effects of Hypothetical Oil Discharges in the Atlantic Coast and Gulf of Alaska (April, 1974), in their chapter on composition and characteristics of oil, deals with this subject in depth.

Page 164

According to the Department of Interior, "No evidence was found in the literature that spilled oil enters marine food chains via absorption or adsorption by phytoplankton and subsequent ingestion by grazing herivores."

Available literature suggest that, "Oil ingested, absorbed, and even adsorbed may enter the food chain when contaminated organisms are eaten," (Evans, Rice, "Effects of Oil on Marine Ecosystems, A Review of Administrators and Policy Makers," Fisheries Bulletin, Vol. 72, pp. 625-638, 1974). Max Blumer (hearings before the Committee on Interior and Insular Affairs, March 23, 1972) states, "Hydrocarbons can be transferred from prey to predator; they spread through the marine food web in a manner similar to that of other presistant chemcials, e.g., DDT."

Page 173

The EIS found that, "This motility (of nekton), combined with irritation sensing ability and natural escape and avoidance behavior, enable them to avoid localized adverse conditions."

This statement is open to question. Several studies indicate that nekton does not show "aversion to the presence of hydrocabrons in its environment and thus may remain in polluted waters for considerable periods." (Sindhu, et.al., "Nature and Effects of a Kerosene-Like Taint in Mullet," FAO Technical Conference on Marine Pollution and its Effects on Living Resources and Fishing, Rome, Italy, 1970). See, also Blumer, "Oil Contamination and the Living Resources of the Sea" and MIT's "Potential Biological Effects of Hypothetical Oil Discharges in the Atlantic Coast and Gulf of Alaska."

The Department of Interior states:

> "The only significant impact on the nekton would be as a result of a massive oil spill which they cannot quickly avoid."

The Arctic Institute of North America list five significant impacts of a massive oil spill on nekton: (1) Destruction of eggs and larvae in spawing and nursery areas; (2) Interference with travel of adult to spawning grounds; (3) Contamination of spawning grounds or nursery areas which prevents egg laying; (4) Alteration of fecundity or spawning behavior of adults; and (5) Disruption of destruction of food sources for juvenile fish. (The Alaskan Arctic Coast, A Backgound Study of Available Knowledge, June, 1974).

This statement does not take into account the effects of chronic low-level pollution. In his toxicity and avoidance tests with Prudhoe Bay oil and pink salmon fry, Stanley Rice concluded that:

> "Even very low-levels of oil pollution can be detected by fry and could stimulate changes in migration routes"

(Proceedings of the Joint Conference on Prevention and Control of Oil Spills, American Petroleum Institute, EPA and the U.S. Coast Guard, Washington, D.C., pp. 667-670). Blumer (1972) and Evans, Rice (1974) also document the effects of chronic low level oil pollution.

The impact statement tells us that the "effects of an oil spill on marine mammals...will be negligible as long as the mammals are able to avoid the area of the spill."

The persistence and movement of an oil spill will be the major factor in determining the extent of impact on marine mammals. "Spills occuring in open water, along a migration route or in a feeding area, will be most disruptive." (Arctic Institute of North American, "The Alaska Arctic Coast, A Background Study of Available Knowledge", June, 1974).

Marine mammals tend to periodically concentrate. A set of circumstances that might ordinarily seem of minor importance could have great impact if timed right. A disaster near the Pribilof Islands in summer, for example, could virtually destroy the entire breeding population of Northern Fur Seals.

Marine mammals are at the top of a very complex food web. Any effect on the lower trophic levels will be reflected in the productivity of some marine mammals. The incorporation of hydrocarbons in shellfish is well documented ("Hydrocarbon Pollution of Edible Shellfish by an Oil Spill,: Blumer, Sonze, Sass, Marine Biology, Vol. 5, No 3, March, 1970, pp. 195-202; "Determination of Polycyclic Aromatic Hydrocarbons in Oysters Collected in Polluted Wasters, Cahnmann and and Kuratsune; "Scientific Aspects of the Oil Spill Problem," Blumer, Environmental Affairs, Vol 1, No. 1, April, 1971). Rice and Evans summarize the manner in which hydrocarbons are passed through the marine food web. (Effects of Oil on Marine Ecosystems, A Review for Administrators and Policy Makers," Fisheries Bulletin, Vol. 72, pp. 625-638, 1974). In addition, simple destruction of a local population of food organisms, or a change in their distribution, could disrupt breeding by marine mammals already limited by scarce breeding sites.

The EIS fails to deal with pressure on marine mammals due to increased accessibility to hunters and an increase in local populations of humans that might disrupt breeding or hauling gounds. (The Alaskan Arctic Coast, A Backgound study of Available Knoweledge, The Arctic Institute of North American, June, 1974).

The effect of spilled oil on sea otters is well documented (Alaska Department of Fish & Game files). Sea otters coated with oil lose the insulating character of their fur, and quickly freeze. The impact of spilled oil on sea otters is almost invariably fatal. Alasak contains the last major habitat for this threatened species, and the impact of chronic and catastrophic oil pollution on the sea otter should not be dismissed as "presumably negligible."

Pages 180-183.

The discussion on impacts on oceanic birds is totally inadequate for Alaskan waters. Several species of sea birds, including Emperor Geese, some subspecies of Canada Geese (including the endangered Aleutian Canada Goose), Black Brant, and others, funnel through Alaskan OCS areas in such a way that a properly timed oil spill could conceivable result in extinction of an entire species. (Alaska's Wildlife & Habitat, 1973).

Other species long-lived and slow to mature, could be seriously harmed by accidents near their breeding areas, either directly or through redistribution of food organisms.

Long-term depletion of sea bird populations could have significant effects on long-term productivity of entire marine ecosystems, for the millions of mobile sea birds almost certainly are essential for the proper recycling of nutrients in these systems.

Page 187

The EIS asserts, "Most benthic marine life does not sustain direct impacts from oil spills."

There is insufficient basis for making this statement. It has been shown that oil becomes trapped in sediments and is then reworked by detritus eaters. (Blumer, "Oil Contaimation and the Living Resources of the Sea," March 23, 1973; Todd, et.al., "Potential Biological Effects of Hypothetical Oil Discharges in the Atlantic Coast and Gulf of Alaska, April, 1974, MIT). The physical weathering of oil in cold ice-rich waters is inadequately understood or considered.

Pages 194-200

The impacts on bays, estuaries, and wetlands are described almost solely in terms of oil pollution impacts. In addition, the massive impacts of dredging and laying of pipeline and support facilities should be noted. As stated earlier, Louisiana loses approximately 16.5 square miles of wetlands habitat per year, and 8 acres of wetlands for each mile of pipeline dredged.

Page 219-249

The assessment of socio-economic impact is an important component of an environmental impact statement. Guidelines for EIS preparation issued by the President's Council on Environmental Quality state, in part, that:

> "...Many major Federal actions...stimulate or induce secondary effects in the form of associated investments and changed patterns of social and economic activities. Such secondary activities, through their impact on existing community facilities and activities, through inducing new facilities and activities, or through changes in natural conditions, may often be even more significant secondary effects. Such population and growth

impacts should be estimated if expected to be significant... and an assessment made of the effect of any possible change in population patterns or growth upon the resource base, including land use, water and public services, of the area in question." 98/

The meaning of this passage seems clear; if any proposed action will result in significant primary or secondary socio-economic impact, those impacts and their effects must be assessed.

The following material is an attempt at evaluating the statements treatment of the socio-economic impacts of the proposed increase in oil and gas leasing on the Outer Continental Shelf. Remarks will be made on the EIS' findings as they relate to Alaska and suggestions made on changes or additions which should be included in the final Environmental Impact Statement.

Before discussing the treatment of specific areas of socio-economic impact, some comments are needed on the statement's general approach. The analysis of socio-economic impact is based on very limited sources of information. In fact, the entire section relies on a study originally done as a report to the Executive Office of the President, Council on Environmental Quality.

BLM appears to be unaware of the number of sources which analyze the onshore impact of oil and gas development. These sources include:

1. Written statement by Alaska Governor William A. Egan to the United States Senate Committee on Interior and Insular Affairs in support of S. 2389, submitted for the record, May 10, 1974.

98/ CEQ Guideline, Section 1500.8(a)(3)(ii).

2. Benefits and Costs to State and Local Governments in Texas Resulting from Offshore Petroleum Leases on Federal Lands, prepared by the State of Texas, Office of the Governor, Office of Information Services for the Texas Coastal and Marine Council, Austin, Texas, November, 1974.

3. Offshore Revenue Sharing: An analysis of Offshore Operations on Coastal States, by Gulf South Research Institute for the Governor's Offshore Revenue Sharing Committee, State of Louisiana, not dated.

While not oil development related, the set of material on Alaska's experience with the proposed Lost River development provides an indication of the actual costs of community infrastructure development in Alaska. Basically a study of the feasibility of constructing a "new town" in conjunction with a large mining operation, estimates of State and Federal cost are given. Although this project included sizable capital contributions by the mining company co-sponsoring the study, valuable information on the constraints on and impacts of large-scale development in rural Alaska can be derived.

Specific publications are:

1. Lost River Long Range Capital Imporvelment and Finance Plan, Pacific Architects and Engineers, Inc., Anchorage, Alaska January, 1974.

2. City of Lost River: Pre-Application Proposal to the U.S. Department of Housing and Urban Development for New Community Assistance, Alaska Consultants, Anchorage, Alaska, October, 1972.

Hopefully, these sources can be incorporated by BLM in their final EIS, providing a more accurate picture of the actual Federal, State and local costs of socio-economic impacts.

The statement flatly states that "Sufficient developable land exists for even the high development cases, projected to the year 2000 by R.P.A." This conclusion is in direct conflict with RPS's actual findings that,,in fact, suitable developable land does not exist in a number of communities and that onshore development must be carefully controlled to prevent major negative impacts on each community's services and economy. 99/

CEQ states RPA's findings in this manner:

> "Even under high development cases, each sample region has sufficient undeveloped land to meet the requirements of OCS-induced development if environmental and locational values were ignored...However, large amounts of undeveloped acreage are really unavailable due to environmental values (e.g., wetlands, ecological sanctuaries, antional parks and seashores, and coastal recreation areas), locational constraints (e.g., excessive slopes, inadequate water, and distance from major population centers) and such factors as local preference for agricultural preservation and low-density single-family housing..
> --Land in some of the potential Alaska staging areas is scarce due to land configuration, native claims and location of natural areas." 100/

99/ CEQ Report at 7-55 and 7-73 to 7-76.

100/ Ibid at 7-76.

Finally, one major purpose of the section on land use in the coastal zone is to predict the impacts of oil-related land needs on the present economy. The EIS states in an earlier section that present industries "...face increasing competition from urban sprawl and concomitant land requirements of the support section of the economy on which the natural resource industries depend." 101/

However, no clear evaluation of the onshore land use needs of OCS development is made in the statement. Nor are the impacts on present economic activities, especially Alaska's fisheries, as a result of competition for scarce industrial sites and existing facilities analyzed. Sufficient evidence of the negative onshore impact of OCS development on Scotland's fisheries exists to make the serious study of this subject a necessity. 102/ As the CEQ report states:

> "Commercial fishing may be seriously damaged by both water pollution and mechancial interference from increased marine activity. Experience in Alaska indicates that per capita income of fishermen may decrease. Consideration must be given to the fact that fisheries are renewable resources and are continuing sources of income, whereas minerals may be depleted in our lifetime." 103/

101/ DES 74-90, Vol II, p. 122

102/ North Sea Oil and Gas: Impact of Development on the Coastal Zone prepared for the Committee on Commerce, United States Senate, USGPO, Washington, D.C., October, 1974, pp. 17, 19-20 and 95.

North Seal Oil and Gas: Implications for Future United States Development, Technology Assessment Group, Science and Public Policy Program, University of Oklahoma Press, Norman, Oklahoma, 1973, pp. 103, 105-107.

103/ CEQ Report at 7-72.

It should also be noted that RPA's analysis pertains only to the Gulf of Alaska; no study was made of Alaska's other six OCS sub-regions.

Major revisions of this section of the impact statment, then, are necessary to bring BLM conclusions in line with existing evidence.

As with most other impact parameters, the effect of increased OCS-related employment will be exaggerated in Alaska. This is true for two reasons. First, the limited commercial and industrial development existing along Alaska's coastline is sensitive to small changes in demand for facilities and services, due simply to its presently small capacity. Second, this limited capacity itself will force a much larger increase in OCS-related employment than would be required in an area with a more fully developed public and private support system.

Accurate employment predictions are essential to develop programs, in both the public and private sectors, to meet the demands for utilities, public services and the support for residential, commercial and industrial needs. However, planning is made difficult by the lack of employment information, as recent experience in the North Sea has shown. "Future growth is difficult to estimate since many companies are unwilling to discuss their future plans. The result is that estimating new employment opportunities has been largely a guessing game, which both handicaps and frustrates planners." 104/

Even when companies do share information with governmental planning agencies, actual employment patterns may be vastly different from predicted trends and thus reduce the effectiveness of planning.

104/ North Sea Oil and Gas, Technology Assessment Group, op. cit., p. 100.

In northeast Scotland and the Shetland Islands, for example, employment connected with OCS exploration grew from 2,665 in December of 1973 to 11,275 in March of 1974, an increase of over 8,600 employees in only four months. One American firm, which originally estimated a need for 900 employees at one fabrication site, actually hired approximately 3,000 workers--fully 333 percent over their original estimate within a six-month period. 105/

To put these employment figures in perspective, the mining and construction work force in the entire State of Alaska in August of 1974 amounted to a total of 13,400 employees. 106/ Based on experience in Scotland, the labor demand surrounding simply the construction of platforms to service the Gulf of Alaska alone could easily match Alaska's present construction work force, without considering the seven additional OCS subregions in Alaska. 107/

The petroleum industry's need for a large work force can result in serious social and economic repercussions. Able to pay high wages to attract employees, the oil industry may create serious labor shortages in other industries, as has occurred in U.K. "Traditional employers are having to compete with the oil industry for personnel and port facilities and the wages for roustabouts have been about twice that fishermen have been earning." 108/ Both the U.S. Senate Committee on

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105/ North Sea Oil and Gas, Committee on Commerce, op. cit., p. 17.

106/ Alaska Economic Trends, Research and Analysis Section, Employment Security Division, Department of Labor, Juneau, Alaska, August 1974, p. 5.

107/ North Sea Oil and Gas, Committee on Commerce, op. cit., p. 14

DES 74-90, Vol 11, p. 230

108/ North Sea Oil and Gas, Technology Assessment Group, op. cit., p. 103.

"High unemployment rates are chronic in Alaska, with levels generally two to three times national averages. A number of factors are at work to produce the problem, including seasonal forces (fishing, lumber and construction are sharply curtailed in winter), low participation in the labor force by natives, and the annual arrival of summer transients, many of whom are unskilled... The paradox of rising unemployment rates at the same time that employeemnt rates are rising is common, owing to the large number of job-seekers that come to Alaska each year. Yet, the situation is projected to worsen during the peak years of work on the Alyeska project; many more persons are expected to apply for jobs than will become available, either directly on the pipeline project, or indirectly because of induced economic growth." 109/

In more concrete terms, the Alaska Department of Labor shows that, while employment has increased by 11,100 persons from August, 1973 to August, 1974, unemployment dropped by only 100 persons, from 12,600 to 12,500. (In July, unemployment reached a peak of 13,600 persons, but about 1,000 persons removed themselves from the labor force by leaving the State, ceasing to look for work, and so on.) 110/

This suggests that, even in periods of rising employment, ederal, State and local governments will experience an increasing demand for social services.

109/ Application of El Paso Alaska Company for a Certificate of Public Convenience and Necessity to the Federal Power Commission, respecting the Proposed Trans-Alaska Gas Project, September 23, 1974, p. 2A.7-12.

110/ Alaska Economic Trends, op. cit., p. 5.

Finally, an overemphasis on petroleum development and associated support industries may create serious readjustment problems when activity associated with the "oil boom" tapers off. In Norway, "A major concern is that North Sea devleopment will result in undesirable dislocations in traditional employment patterns and that the economy will be overheated." 111/ This concern is echoed in the Shetland Islands as well:

> "The very size of the population increase, mainly migrants from the mainland, and the differences in outlook between traditional islanders (mainly fishermen and farmers) and the newcomers, will make integration a very difficult goal to achieve. Development of the Shetlands into a major oil base is very likely to lead to significant changes in the entire way of life of its citizens. Higher wages in the oil-related industries will have a major impact on employment in agriculture, fisheries, tourism and the knitwear industry. Many of of those presently employed in the traditional industries, particularly the young, will be attracted to the oil industry by higher wages. Eventually, the Islands could end up with one major employer--the oil industry. The danger of such development would become evident some thirty ot forty years from now when the 'oil boom' dies." 112/

Reinforcing this pint, the Committee on Commerce report states that British authorities "fear... that without proper planning the structural changes in employment resulting from oil and gas development could have disastrous effects on the economy once exploration activities and the platform building boom come to an end." 113/

111/ North Sea Oil and Gas, Technology Assessment Group, op,cit., p. 109.

112/ North Sea Oil and Gas, Committee On Commerce, op. cit., p. 32.

113/ Ibid., p. 14.

In both the preceding discussion of employment and this paragraph on population, a number of references to OCS development in the North Sea are made It should be noted that the total oil reserves in the British sector of the North Sea are comparable to undiscovered recoverable reserves predicted for the Gulf of Alaska alone. The area in North East Scotland which is receiving the most direct petroleum impact is very similar to Alaska; the coastal communities are rural in nature, with limited infrastructure development and a reliance on traditional occupations such as fishing. The build-up of public and private services necessary to support oil development in Scotland can be considered as potentially equivalent to the demand which will be placed on the Gulf of Alaska's coastal communities and on Alaska in general.

As very little petroleum-related support services and public facilities infrastructure existed in many parts of rural Soctland, the employment effects have been, and will continue to be, extreme. Direct employment, originally forecasted by the North East Scotland Development Association (NESDA) to reach 5,000 individuals by 1975, now appears will be at least 7,500 people. The multiplier found for Scottish development would raise total employment by 11,250 to 15,000 people within six years of the first major exploratory find. (Note: The multiplier used--.5 to 1.0-- appears low, as a variety of support services is included in the "direct" employment figure, including over 200 companies involving exploration, field operations, shipping, technical and general supplies. This lower multiplier, however, may indicate more accurately the manpower needs generated in the "social

services" and public facilities support sector.) Assuming 65 rigs and platforms operating at peak production in 12-15 years, a total oil-related and supporting services employment of 30,000-40,000 persons is forecast, using a figure of 450-600 jobs/platform developed through NESDA's research. 114/ This figure, for increased employment alone, is higher than the statement estimate of a total population increase of 20,000 persons forecast for the Gulf of Alaska to the year 2000. A ratio of two dependents-employee would result in a total population increase of 90,000-120,000 people for the life of the field. However, total population increases for North East Scotland have been projected as high was 220,000 people, with increases of 20,000 persons in each of the onshore service centers providing direct support to the OCS activity.

Applying these figures developed by NESDA to the projections of activity in the Gulf of Alaska to 1985 published by BLM, the total employment generated by 19 production platforms would be 8,500-11,400 persons, with a total population increase of 25,000-34,000 people. Total employment and population figures for the year 2000, based on BLM's estimate of 60 platforms in operation, are 27,000-36,000 jobs, with a concomitant population increase of between 81,000-108,000 people (or roughly one-third of Alaska's 1973 population).

These estimates become even more disturbing when the overall scope of OCS development in Alaska is considered. Various estimates of resources in Alaska's combined OCS region place undiscovered recoverable reserves at roughly twice those presently discovered in the British

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114/ North Sea Oil and Gas, Committee on Commerce, op. cit., drawn from information in Appendix C, pp. 83-85.

sector of the North Sea. However, Alaska's OCS regions are widely dispersed and cannot be serviced from the limited number of onshore facilities as is possible in the North Sea. The Northern European nations surround the North Sea, so the majority of the North Sea can be serviced from a few intensely developed locations; here, however, Alaska is surrounded by a number of potential OCS developments along the entire 47,300 miles of Alaska's costline. Therefore, onshore service and supply locations will be multiplied far more than would appear to be necessary in a superficial comparison of potential oil reserves.

The disaggregation of onshore facilities and support centers necessitated by Alaska's expansive geography means that the opening of additional OCS subregions to oil exploration and development will result in a more than proportional increase in labor needs, population, and demand for public services. This is supported by BLM's statement that, "of the 47,300 miles of Alaska coastline, less than 1 percent (300 miles) is considered developed." 115/

Using data published by BLM, it is possible to predict the total population increases generated by the accelerated development of Alaska's OCS. Assuming, for the above reasons, that all labor and facility needs will be duplicated in each OCS subregion, the number of developments equal to the Gulf's oil potential can be generated. BLM estimates that potential oil reserves in Alaska's OCS amount to 85 billion barrels; this amounts to over four times the potential oil reserves of 20 billion barrels forecast for the Gulf of Alaska. 116/

115/ DES 74-90, Vol. II, p. 121

116/ Ibid., Vol II, Table 73, p. 139.

Assuming proportional labor and population impacts (especially if all Alaska OCS areas are leased within the four-year period established by BLM), total population increases may amount to 344,000-459,000 people, with 115,000-153,000 new employees. (This compares with a total State labor force estimated at 147,000 persons in June, 1974. 117/

From the figures developed above, therefore, it is not inconceivable that the concentrated exploration and development of two or more of Alaska's OCS subregions could result in more than doubling Alaska's present population.

The purpose of these population and employment estimates is not to provide an accurate picture of future population impacts. It is rather an attempt to indicate the extreme magnitude and seriousness of possible impacts of concentrated OCS development. The final EIS must be expanded to include an analysis of statewide population and employment impacts for the development of all OCS regions. At present, the draft EIS statement considers development only in the Gulf of Alaska and, as shown above, with apparently limited accuracy.

However, even without considering such dramatic population predictions, intensive OCS development will seriously stress various elements of Alaska's infrastructure.

No systematic analysis of the present level or capacity of Alaska's transportation network is provided. As the limited transportation system in Alaska is a key constraint on economic development, the timing and extent of OCS resource development will be affected. Likewise, where OCS-related development necessitates the extension

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117/ Alaska Economic Trends, op. cit., p. 5.

Oil and Gas states, "oil field support operations require special facilities, including capability for round-the clock operations and water depths adequate for a variety of vessels. In addition, most servicing companies need storage facilities within a short distance of the dock." 118/ The more extreme weather conditions in the Gulf of Alaska mean that heavier platform and storage facility construction will be necessary, which, in turn, involves more extensive harbor and port facilities.

New developments in oil production technology indicate that concrete may replace steel structures where water depth and extreme weather conditions have stretched earlier technologies to their limits. However, concrete production and storage structures require large, deep water construction sites. 119/

Finally, the reliance on waterborne commerce to meet the needs of OCS development will completely overburden present port facilities. Of the approximately 23.5 million short tons of waterborne commerce within Alaska in 1971, quoted in the BLM report, 120/ only 532,000 short tons found its way to the major ports surrounding the Gulf of Alaska. An additional 2.5 million short tons was destined for Anchorage or Whittier (713,000 tons) a major trans-shipment point for Anchorage bound goods. In 1973, this situation had changed very little, with 636,351 tons bound for Gulf ports, and 3.0 million tons destined for Anchorage, and a State total of 25.4 million short tons. Furthermore, although 1973 figures are incomplete, fish and fisheries products accounted for 30 percent to total 1971 Gulf port tonnage. 121/

119/ North Sea Oil and Gas, Technology Assessment Group, op. cit., p. 66.

120/ DES 74-90, Vol II, p. 129.

121/ Waterborne Commerce of the U.S., op. cit.

Experience in the North Sea indicates that each platform operations in the OCS requires 25,000 tons of equipment a year, with two to three supply boats operating continuously. In the field predicted by BLM for 1985, this would add 40-60 vessels to Gulf of Alaska commerce with 500,000 tons of equipment directly attributable to field activity. This does not, however, include the other commodities necessary to support the onshore facility such as food, fuel oils, building materials and other commodities. Operating on an eight-day schedule, these supply boats would add 1,840-2,760 arrivals to the present totals. This compares with Cordova's 1971 traffic count of 1,158 vessels, which handled a total of 68,553 short tons. Supply boats alone would more than double the traffic at Cordova's presently insufficient harbor and increase total tonnage by roughly 700-800 percent. (Note: This dramatic increase in traffic places additional stress on the marine environment, especially in harbor areas, through greatly increased oil ballast water and waste disposals by the increased number of ships.)

Using the multiplier developed above for development of Alaska's entire OCS area, the platform supply boats alone would increase total shipping by over 2 million tons, or roughly 8.5 percent of Alaska's total 1973 shipping.

The overall impact of OCS-related shipping is difficult to predict, as OCS development in Alaska will rely on water transportation to a much greater extent than in other OCS areas, in both the United States and abroad. A superficial look at a State map shows the reason for this; of the approximately 80 cities and boroughs located on tidewater, only four are interconnected by road or raillines, and these are located only in the northwest Gulf of Alaska. The remaining seven OCS regions in Alaska are accessible only by water or air. This means

that all building materials, goods, industrial supplies, food, housing, fuels, and so on, which are normally brought to OCS development sites by road or rail must be shipped by water or air. (Or, conversely, the State and Federal governments may find themselves under oil company pressure to permit, or even financially support, the construction of roads to some remote onshore site important for the development of a particular OCS area.) (Note: The present trans-Alaska pipeline haul road may provide future access to the Beaufort Sea area.)

The lists of harbor, roads and railline improvements to be undertaken in Scotland to support oil development indicate some of the reliance on overland shipping. Nearly $ 1/4 billion in improvements of major highway routes were scheduled by 1972. Nine major ports had literally miles of additional wharf space in the planning or construction phases, as well as the construction of new staging, warehousing and fabrication sites. The rail systems, which carry much of the steel, cement and pipe used in North Sea oil development, found it necessary to expand both passenger and industrial routes and facilities. 122/

Considering the massive volumes of materials, equipment and manpower needed in the construction of platforms, service areas, staging and warehousing sites, fabrication sites, living areas and additional port facilities, it would not seem beyond reason that concentrated OCS development in a number of OCS subregions would more than double Alaska's total waterborne commerce tonnage. In addition, port facilities will have to be "overbuilt" somewhat, as unreliable weather and sea conditions will necessitate increased storage areas and higher peak cargo handling capacities to offset those periods when shipping traffic will be interrupted.

122/ North Sea Oil and Gas, Committee on Commerce, op.cit., Appendix F, pp. 135-137

It is essential for BLM to analyze the effect of widespread OCS development on Alaska's waterborne transportation facilities and the overall pattern of transportation systems in Alaska.

As in the case of harbors and port facilities, air transportation will be heavily impacted in Alaska. Again, the dependence on air transportation is magnified due to the limited road and rail systems presently available.

Air traffic has increased greatly in North East Scotland following oil discoveries in the North Sea. During 1971-73, passenger traffic has increased at an annual rate of over 35 percent at the Aberdeen Airport; passenger traffic increased by well over 50,000 persons in 1972 alone. This increase in air service was even more drastic in the less populated areas--one airport in the Shetlands recorded a 60 percent increase in air traiffic during 1972. 123/

As stated in the Committee on Comerce report, "The need for fast personal communications underlines the important part that will be played by air services in the North Sea oil industry." 124/ Scotland however, has a more fully developed road and rail network than Alaska. Therefore, air transporation servicing oil development in Alaska is likely to include the shipment of large volumes of materials and supplies, as well as personnel, This would create additional land use impacts, as off-loading and storage facilities will be a necessary part of airport improvements.

123/ Ibid., pp 79-137

124/ Ibid, p. 137.

The interior airports will also be impacted by OCS development. As road or rail-connected airfields, Anchorage and Fairbanks will serve as major change-of-mode points. This phenomenon is clearly seen in Fairbanks as a result of trans-Alaska pipeline construction. The total volume of freight arriving at Fairbanks International Airport in FY 1974 amounted to 21,635 tons, an increase of more than 64 percent over the entire 1973 total. However, the amount of freight departing Fairbanks International Airport in the same fiscal period, at 69,662 tons, was more than triple the amount of incoming airfreight. 125/

With only two major civilian airports to service Alaskan OCS development, this impact would be multiplied by the concurrent exploration and development of two or more OCS subregions.

The impact of OCS-related airport developments on statewide transportation patterns should not be overlooked. Aberdeen, Scotland, for example, has become the biggest helicopter base in the whole of Britain. 126/ Closer to home, unofficial reports indicate that roughly 15 separate operators have applied for helicopter rights for the Yakutat airport alone!

The analysis of airstrip, capacities, relationship to possible OCS development and transportation patterns, needed improvements and the environmental and economic impacts on Alaska are necessary parts of the draft environmental impact statement which are notably lacking in the present document.

As the previous discussion of surface transporation has shown, there are essentially no roads or road systems of any use to industrial devèlopment in five of Alaska's seven OCS subregions.

125/ Operational Growth Indices for Fairbanks International Airport, Division of Aviation, Department of Public Works, State of Alaska, December, 1974, Section on "Air Cargo Analysis."

126/ North Sea Oil and Gas, Committee on Commerce, op. cit., Appendix C, p. 79.

If the large scale and rapid development of Alaska's OCS as envisioned by BLM actually occurs, the State and Federal Governments will be under very strong pressure to extend the existing surface transportation network to include these OCS regions. This could result in the construction of literally thousands of miles of new roadways through some of the most extreme soil, weather and topographic conditions in the world.

The effect of such a construction program on State and Federal budgets would be of equal magnitude. Before a policy of increased OCS leasing can be considered, then, an intelligent analysis of these potential, and perhaps unavoidable, costs is necessary.

Finally, the present road network, even though limited to interior areas, may be severely impacted by the large volumes of traffic necessary to support OCS development. As the construction of the trans-Alaska pipeline has indicated, the existing industrial supply, agricultural and technical support services in Alaska are insufficient to handle large-scale industrial developments. A large proportion of the supplies necessary to support this massive construction project had to be imported from the continental United States. The existing road network and its connections with the Al-Can Highway and various water transportation routes are an important and heavily used link in the overall transportation network.

The term "community infrastructure" includes a wide range of community services (police, fire, health and welfare, education); community facilities (water, sewage, solid waste, power, streets, public buildings); and the administrative capability to provide those services and facilities.

An analysis of impacts on community infrastructure should include three components: the increased demand placed on community infrastructure as a result of primary and secondary impacts of OCS development; the increased cost to meet these demands; and the capability (both financial and administrative) to pay for increased costs. This latter point would include an assessment of manpower availability, skill levels and impact on costs and revenues at both the State and local level.

BLM's present treatment of the impact of OCS development on community services and facilities is limited to a very general discussion of overall effects. No estimates of costs to local, State and Federal agencies are provided. An accurate estimate of the capability of each OCS subregion to meet those costs is also lacking.

In a quote from RPA's research, the BLM report states:

> "...a comprehensive regional planning effort will be required to properly integrate OCS-induced development into a regional economy. This will be necessary to....(3) develop infrastructure facilities and services to support the population induced by onshore OCS development. Since the planning effort must come in advance of the new governmental revenues that OCS development could bring, Federal and State planning support will likely be required. This support will be particularly important for less developed areas or areas with limited governmental planning and administrative capabilities." 127/

An indication of the potential impact of OCS development on community infrastructure can be derived from figures quoted in BLM's report. In comparing 1985 high OCS development with 1970 and projected 1985 population levels, the population multipliers for the following communities evolved. 128/

127/ DES 74-90 at Vol. II, pp. 227-231.

128/ Ibid., Table 84, Vol. II, p. 247.

1985 High OCS Development	Valdez	Cordova	Seward	Yakutat
Increase over 1970 population level	1,155%	400%	317%	1,740%
Increase over projected high 1985 population	44%	111% (2x)	127% (2 1/4x)	1,050% (11 1/2x)

Depending on the location and extent of OCS development, then, these communities may be expected to provide facilities and services at up to 18 times their present levels. In actuality, municipal budget/manpower may have to increase more than this amount, as most communities presently do not provide the range of services necessary in a large community. Additional functions would need to be added to municipal governments, as well as having to expand present services by tremendous proportions.

Also, it should be noted that these communities located in the Gulf of Alaska represent the most highly developed level of community infrastructure in any of Alaska's OCS regions. The communities surrounding the Beaufort Sea, Chukchi Sea, Bering Sea, Bristol Bay and Aleutian OCS subregions have even lower overall levels of community development. The impacts on these areas, then, will be even greater than those forecast for Gulf of Alaska communities.

As BLM states:

> "The resultant demand for services--for example, schools, hospitals, transportation facilities, residential housing, electric and water utilities would require considerable planning and increases in local government expenditures. The ability of a given community to cope with this growth depends on its size, its existing capacity to plan and control growth, and its financial structure." 129/

129/ Ibid., Vol. II, p. 246

CEQ states that"...small areas and those without much experience in handling growth may be unable to meet demands" placed on their community infrastructure. 130/ The impact figures given above the summary profiles of the Gulf of Alaska communities suggest that Alaska's municipalities will be overwhelmed by OCS development. The burden of meeting these infrastructure needs of OCS-induced development will likely lead to massive commitments of Federal, State and/or industry funds.

The final impact statement prepared by BLM should include additional analysis of the infrastructure costs associated with its increased OCS leasing policy. Perhaps this analysis can be restricted to those areas where expected impacts are large in proporation to present development. The EIS states that "population increases in most regions would be less than 5 percent, except in Florida and Alaska, where the impacts would be larger." 131/

Where these impacts would be grossly above this "5 percent" figure, as in Alaska, the further quantification of potential impacts should be provided in BLM's analysis of OCS development policy.

In discussing the potential impact of OCS-related onshore development, CEQ states:

> "Although land use planning and controls can reduce the damage of such development to the environment and to the fiscal capacity of a community, the pace at which development occurs and the tremendous changes that it will bring in some communities make careful analysis of the effects of the development an essential part of any community's decision to allow the refineries and other facilities to come in." 132/

130/ CEQ Report at 7-75.

131/ DES 74-90 at Vol. II, p. 246.

132/ CEQ Report at 7-73.

It would be well for BLM to adopt this same philosophical approach as the OCS leasing policies eventually adopted will determine in large part the timing and magnitude of these onshore impacts and, in turn, the actual increased costs to industry, the State and to the Federal government.

In a recent conference conducted by NOAA respecting its environmental research study plan, the conference recommended that a comprehensive socio-economic research program be developed and undertaken to provide a model to forecast socio-economic impacts resulting from a variety of OCS development scenerios. This is precisely what is required for Alaska OCS and the State urges BLM to implement the recommendation.

Pages 250-254

In a "Summary of Aggregate and Cumulative Impacts of Expanded Programs and Comparison with Impacts under Current Leasing Program, a. On Biological Communities of the Coastal Zone," mention is only made of the effects of oil spills. There is nothing about the effects of chronic low level pollution, drilling muds, formation waters, chemicals used during drilling, etc. All of these will impact the biological communities. (The Alaskan Arctic Coast, A Background Study of Available Knowledge, Artic Institute of North America, June 1974, pp. 498-508), Rice, Evans, "Effects of Oil on Marine Ecosystems: A Review for Administrators and Policy Makers," July 1974, Fisheries Bulletin, Blumer, "Scientific Aspects of the Oil Spill Problem," Environmental Affairs, April 1971.)

The EIS states: "Pipelines would probably not be permitted to cross bays and estuaries with shellfish banks. The impact is generally relegated to the massive oil spill, an unpredictable event in any area." The statement is optimistic, but not borne out by practice in the Gulf of Mexico. If states are not allowed sufficient time to complete their coastal zone management planning processes, and to acquire mechanisms to effectively implement those plans, then there is no guarantee that pipelines will not indeed cross bays and estuaries with shellfish banks. In many cases, states will be forced to choose between (1) a "safer" pipeline violating a sanctuary and (2) a less safe pipeline circumventing a sanctuary, when the best choice would have been no pipeline due to the value of biological resources.

The impact statement admits that the effects of pipeline dredging on wetlands "are difficult to assess because of inade-

quate baseline information." The State concurs, and again asks that no decision on leasing be reached in any particular frontier area until baseline studies are complete.

Page 258

According to the Department of Interior, "The only adverse effect on sport fishing that could result from offshore operations is the massive oil spill."

Most available data indicates that chronic low level pollution constitutes as grave a threat as that of a massive oil spill. Rice ("Toxicity and Avoidance Tests with Prudhoe Bay Oil and Pink Salmon Fry") indicates that chronic low level pollution could stimulate changes in migration routes. This would be a major impact on sport fishing. In addition, traffic in tugs, rig-tenders, rigs themselves and eventually tankers, especially when concentrated to enter or leave port, can result in serious degradation of sport fishing by interfering with gear and decreasing the "wilderness" values of the fishing experience.

The impact statement seems to differentiate between the impacts on commercially valuable fish and shellfish and recreationally valuable fish. In Alaska, where in most cases they are the same fish, this is not a valid distinction.

Page 259

The EIS states "adverse impacts on these organisms (endangered and threatened wildlife) would be the same in nature and quantity as to other fauna in particular geographic regions." In fact, as we noted above, at least one endangered species in Alaska (Aleutian Canada Goose) could be completely eliminated by a single oil spill.

This statement is simply another indication of the Department's shirking its responsibilities under the Endangered Species Act. (See

supra) The Department's representation that it will take "adequate mitigatory measures" to prevent adverse impacts on endangered and threatened species reveals nothing of the specific steps which the Department will implement to protect these species from adverse impact.

Page 260-262

The Department raises the spectre of refineries and onshore support facilities emitting substantial emissions, including sulfer dioxide and particulate matter. No mention is made of the relationship between these emissions, regional air quality and the national goal of avoiding significant deterioration of existing pristine air quality--such as exists currently in most regions of Alaska.

Page 262-265

The discussions of impacts on water quality are incomplete. As has been noted before in these comments, production water discharges can result in hundreds, if not thousands, of barrels of oil being discharged from particular platforms per year. In addition, substantial quantities of raw sewage may be discharged from the platform. Pipeline construction can result in a deterioration of water quality not only through dredging but also through salt water intrusion into sensitive wetland areas. The water quality section also does not deal with the toxic components of drilling fluids which are currently allowed to be discharged into the ocean. Finally, other intentional discharges--such as ballast water discharges from tanker activity--are not covered. Indeed, there is a general lack of emphasis on the particular problems involved in these "planned discharges"--that is, those discharges, such as ballast water discharges, production and deck drain oil discharges,

etc., which create and aggrevate problems of chronic low-level pollution in a particular area.

Page 265

The EIS states:

"The aggregate and cumulative impacts on air and water qualities that will result from the 10 million acre proposal are impossible to determine. Extensive baseline data must be accumulated from the literature and field and follow-up monitoring studies conducted as the Gulf of Mexico can provide little baseline data."

The State of Alaska agrees. However, in light of this statement, and other statements made in the impact statement which underscore the need for the gathering of baseline and experimental data, the State questions how an adquate draft environmental impact statement on the Gulf of Alaska can be prepared some 3 1/2 years before receipt and analysis of sufficient environmental information.

Pages 269-273

Although BLM discussed the removal of sea floor, the creation of obstructions, the contamination of fish and reduction of fishing effort due to spilled oil and the removal of potential onshore aquaculture sites, the primary socio-economic impact on the fisheries industry is completely overlooked.

As suggested in the preceding discussion on port and harbor facilities, the competition for limited port facilities and industrial facilities will greatly hamper the fisheries industry. In extreme cases, the fishing industry might be entirely eliminated in specific areas.

As fisheries is a heavily labor intensive industry, presently

estimated at between seven and ten per cent of Alaska's employment and up to 20 per cent during peak periods, any negative impacts on the fishing industry will reverberate throughout Alaska's economy. 133/

The discussion of removal of the sea floor from use is oversimplified in implying that rigs will "remove" only that acreage they actually occupy. In fact, ocean floor structures that are likely to cover oil are also those that are most likely to attract commercially valuable fish, a spatial coincidence noted frequently by North Sea fishermen. In addition, fog, darkness, the required "shapes" of trawls, pot-sets, and long-lines, and the heavy traffic of rig-tending vessels, greatly enlarge the size of the area from whence commercial fishermen are effectively excluded.

If trade-offs between fisheries and the petroleum industry do occur, Alaska's employment (and unemployment) conditions will suffer, as the jobs lost in fisheries will likely not be made up in the relatively capital-intensive petroleum sector, especially in the long term.

A very serious and in-depth analysis of the potential economic impacts on Alaska's fisheries and, in turn, on Alaska's economy from OCS development is necessary.

This same criticism is true of the BLM documents, Section V.E.; again, no thought is given to the unavoidable effects of competition for limited port and industrial on the fishing industry.

Page 284-285

The State is confused by the Department's discussion of "Impact of Proposed Action on Existing Level of Environmental Study Prior to Leasing." On page 285, the EIS states that the "designation by

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133/ Estimated from employment figures provided by Alaska Department of Labor, commercial licenseholders recorded by the Alaska Department of Revenue, and A Limited Entry Program for Alaska's Fisheries, Governor's Study Group on Limited Entry, State of Alaska, February 1973, pp. 130 and 131.

the Secretary of the scheduled frontier areas to be opened will determine the studies schedule. Baseline studies must precede leasing for validity." This is in conflict with other statements contained in the environmental impact statement, and other extra-eous documents previously referred to, which state quite clearly that the Department of Interior intends to lease the frontier areas, particularly the Gulf of Alaska, many years before receipt and analysis of sufficient environmental data. Indeed, the National Oceanic and Atmospheric Administration, as previously noted, believes that four years is the minimum time in which sufficient information can be gathered. Indeed, the first year of this research effort by NOAA has yet to be completed. However, formulation of the Gulf of Alaska site specific environmental impact statement is currently underway. For the impact statement to say, on the one hand, that the baseline and experimental studies must precede leasing for validity, then, on the other hand, to state that it would serve no valid purpose to delay leasing until completion of these studies, does little more than allow the impact statement to impeach itself. Some substantial clarification is needed.

Page 285-286

The section on the impact of the accelerated leasing proposal on the supervision function of the USGS is certainly not adequate. As mentioned before, specific projections, running several years in advance, should be given as to the estimated numbers of inspectors and other supervisory personnel which will be needed to adequately police the frontier areas. The fact that ten inspectors will be assigned to "other areas" of the country in FY '76--presumably all of Alaska--is not encouraging to the State. The impact statement

should provide a more detailed projection.

SECTION 4

Pages 287-303

The State finds Section 4 of the impact statement particularly deficient. Few, if any, substantive mitigating measures are proposed. The State would recommend that all of the following mitigating measures be incorporated into the impact statement.

1. USGS should establish stringent Federal standards for critical OCS operator personnel and certify or provide for accreditation of training programs which may be initiated by either the government or industry. Industry itself concedes that most accidents related to offshore oil drilling are caused by human failure. Only by rigorous peronnel training can USGS hope to improve the safety record of offshore oil development activity. In addition, the USGS itself should provide for a comprehensive training program for all inspectors and other supervisory personnel.

2. Exploratory drilling instrumentation to monitor downhole pressure at the bit is insufficient. 134/ No drilling in frontier areas should be allowed until industry possesses the capability to adequately gauge precise downhole pressure at all times during exploratory drilling.

3. Fixed platforms during the exploratory drilling phase should be specifically forbidden in the Gulf of Alaska. The CEQ Report noted: "drilling platforms have been lost in the North Sea, some quite recently." 135/ Because of the frequency and unpredictable nature of storms in the Gulf Coast, and the high probability of earthquakes and tsunamis, fixed platforms present unnecessary dangers to Gulf operations.

4. Ocean disposal of drilling muds, drill cuttings, sewage,

134/ CEQ Report at 8-6.
135/ CEQ Report at 8-7--8-8.

production water or deck drain water with oil residues should be prohibited in any frontier area. This requirement would be in conformity with proposed new source and best available control technology standards proposed by the Environmental Protection Agency. (See supra) The potential dangers of chronic, low-level contaminant to such fragile ecological areas as the Gulf of Alaska are simply too great to be dismissed by the talisman of economy.

5. The best demonstrated environmental control technology should be employed in all phases of exploration, development, workover and other operations associated with offshore oil and gas development. We agree with the National Academy of Sciences that, if the employment of the best demonstrated control technology is economically infeasible in a particular area, no drilling should be allowed in that area until such control does become economical. 136/

6. Sub-sea completion should be mandatory in the Gulf of Alaska. The decreased environmental risks associated with this developing technology have led the Council on Environmental Quality to recommend its utilization in fragile frontier areas. 137/

7. Offshore oil platforms should not be located where they may pose any measureable threat to endangered or threatened species, important spawning and breeding areas, key scenic and recreational areas, important commercial or sport fishing grounds or other areas of high renewable resource utility. Through strict analysis of tract selection, these goals can be readily accomplished.

8. A prohibition on simultaneous drilling and workover operations from the same platform.

9. The conditioning of pipeline right-of-way corridors on adequate assurance that pipeline installation and maintenance will

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136/ CEQ Report at NAS-32.
137/ ID. at 8-12.

have no measureable adverse impact on estuaries, wetlands, or other biologically productive areas.

10. Prohibition of the use of offshore storage facilities in areas which pose weather or seismic risk, such as Gulf of Alaska. Offshore storage facilities capable of holding up to one million barrels have been utilized in the North Sea, and the President's Council on Environmental Quality has outlined the risks involved in the use of these facilities in the Gulf of Alaska. 138/

This list of mitigating measures is not exhaustive, and does not include managerial or programmatic mitigating measures which are better discussed in the impact statement section on alternatives, or which have been dealt with previously in other sections of these comments. In addition, the final EIS should discuss the mitigating measure offered in Chapter 8 of the CEQ Report. In venturing into Alaskan waters, the oil industry will be conducting operations in an area with far greater long term resource potential than merely the extraction of oil and gas.

It is absolutely essential that mitigating measures be adopted sufficient to insure that the long term productivity of renewable resources will not be measurably compromised by either offshore or onshore OCS operations.

SECTION 5

Unavoidable Adverse Impacts

In discussing pages 304 through 316 of the impact statement, the State would like to divide its comments in two sections. First, the analysis of "Unavoidable Adverse Environmental Effects" does not include several adverse environmental effects which have traditionally been associated with offshore oil and gas development.

138/ Id. at 5-11.

Second, the statement includes many impacts which are, indeed, avoidable with application of more sophisticated tecnology.

In its discussion on impacts to marine organisms, the impact statement alludes to the problems of chronic or low-level pollution caused by "intentional" discharges, such as production water and ballast discharges. However, in light of the comments made previously by the State on this impact statement, this section should be substantially amplified. There is a very large body of material on the subject.

Under unavoidable impacts to wetlands and beaches, the impact statement glosses over the mammoth impacts which pipelines and the onshore facilities will have on wetlands and beaches. As these comments have stressed, it is an endemic fault of the impact statement that it underestimates the problems of onshore impacts to offshore oil development. For purposes of this section, it should again be noted that mammoth losses of wetlands in Louisiana have taken place because of OCS-related pipelines and other onshore facilities.

The statement on page 310 that "degradation of water quality by routine operations will be slight" is not true. Throughout these comments, and throughout other criticisms of BLM's program, the severe problems of chronic low-level pollution have been stressed. Again, it is incumbent upon the Department of Interior to thoroughly describe the potentially massive effects of chronic pollution caused by intentional discharges to marine biota and onshore communities.

Conversely, many of the impacts which the DES states are unavoidable can be avoided by applying precisely that level of technology

recommended by the Environmental Protection Agency and the Council on Environmental Quality and mandated by the Federal Water Pollution Control Act Amendment of 1972. For example, adverse impacts associated with drilling muds, drill cutting, and production water discharges can be avoided by simply banning the discharge of these materials into the waters. Impacts to wetlands and beaches can be minimized by strict conditions and stipulations on right-of-way permits, and by requiring permittees to fully disclose their development plans to all concerned Federal and Stage agencies for review and approval prior to the granting of a right-of-way permit.

Under deterioration of airquality, no mention is made of the potentially severe deterioration of air quality associated with onshore facilities such as terminals and refineries. Reference should be made to an air quality permit recently granted by the State of Alaska to Alyeska Pipeline Service Co. for their onshore terminal to service the Trans-Alaska pipeline. Potential sulfur dioxide emissions from that terminal will deteriorate existing clean air in the Valdez area down to national secondary standards. These problems would seem inherent in onshore industrialization.

Throughout the impact statement, the Department refers to potential damage to "historical and archeological sites, structures and objects." A minimal degree of sensitivity to Alaskan conditions would reveal that many Alaskan coastal communities are composed primarily of Indians, Aleuts and Eskimos. The cultural heritage of these peoples are more than structural relics, they are living examples of alternative cultures fighting for survival. In Yakutat, for example, it is predicted that onshore development associated with OCS activity in the Gulf of Alaska will obliterate the Native

life stype of that community. Similar impacts can be anticipated throughout the Bering Sea. Under unavoidable impacts, the Department should admit that the massive influx of personnel, materials and support facilities will have a significant, if not total, adverse impact on the Alaskan Native culture.

The discussion of the conflict between OCS development and agricultural use does not reflect real land use issues, especially in relation to Alaska.

First, no indication of the actual magnitude of potential land use conflicts is provided. Even a very rough range (thousands of acres, tens of thousands, etc.) would be helpful.

Secondly, due to the low level of community and resource development along the coastline bordering Alaska's seven OCS regions, massive impacts resulting from secondary (support services, community development, etc.) activities will also be unavoidable. BLM should also estimate the magnitude of these conflicts with present land use.

Finally, the impact of OCS development on agricultural land use is of minimal importance in Alaska. Of more concern to this State are the unavoidable effects on other community and industrial land uses. Competition for scarce developable land in some OCS subregions may severely hamper normal, non-oil related community growth and commercial development.

Also, because of the large sections of coastal areas in present or proposed preservation areas, impacts on this type of land use will also be unavoidable. BLM, however, does not consider the very real social and economic impacts of conflicts between these land uses and OCS land needs.

The transfer of thousands of acres of land devoted to the maintenance of living renewable resources to intense community and industrial use will have unavoidable impacts on the land area available for nesting grounds, breeding areas, etc., on all portions of Alaska's coastline. As these resources are used by people in Alaska and, for migratory species, other parts of the United States, for food supply, sport hunting, and so on, changes in population levels due to land use conflicts will have a "real" social impact.

In the case of resources harvested commercially, conflicts between OCS and natural land uses may have long term economic impacts. For example, as BLM states:

> "The northern fur seal supports a considerable commerical enterprise based on its pelt. Management is shared by several nations. Its main breeding grounds are the Pribilof Islands, west of Nome, where they are harvested . . . . Between 40,000 and 50,000 fur seals are taken annually, for a gross income of about 3 1/2 million dollars . . . ."

The Pribilof Islands, however, are located within the Bering Sea OCS subregion, and, in fact, BLM is presently soliciting nominations for oil lease tracts in an area which surrounds one of the four islands. Intense OCS development in this area will lead to unavoidable land use conflicts, as the Pribilofs are the only land mass within 250 miles. Some thought should be given to the economic impact of OCS development on existing resources and on the international impact of any OCS development disruption of a multi-national economic agreement.

This same in-depth analysis of the unavoidable socio-economic effects of OCS development on land use must be extended to all of

Alaska's OCS subregions.

(As an aside, even BLM's description of the location of the Pribilof Islands is misleading. While they are located "west of Nome" by about 150 miles, they are an additional 550 miles south. The Pribilofs are tied much closer to other communities, relying on the transportation and communication networks in the Bristol Bay and Aleutian areas.)

SECTION 8

Page 324-332

Alternative (A)-- "Alternative Sale Scheduling to Increase OCS Leasing"--is a confusing section. If, in the final environmental impact statement, the Department adopts the approach recommended in these comments, that is, incorporation of the five-year planning schedule in the impact statement, then this alternative will take on increased significance. That is, specific alternative lease schedules can be analyzed with reference to the five-year planning model prepared by BLM. As the discussion stands, this subsection provides no more insight in the possible scheduling alternatives than does the remainder of the statement itself on the implications of the existing schedule.

This section should be thoroughly revised, to compare significant alternative leasing schedules to the existing five-year program in such critical areas as relative environmental impacts, timing and availability of estimated resources, responsiveness to regional demand markets and current level of technology. Moreover, the alternative lease scheduling should be analyzed with reference to the specific criteria which these comments have requested to be incorporated in the document for determing leasing priorities.

Pages 333-338

Analysis of alternatives B and C are of little analytical value, precisely because of the necessity of the current program, that is, leasing 10 million acres per year, has not been demonstrated. If the benefits of the 10 million acre proposal are put forth in the impact statement, then the relative costs and benefits of program reorientation can be more intelligently discussed.

Page 338

The impact statement suggests that "basically safe technology is available, provided its application and use are properly regulated and controlled." Even if this statement can be conceded in relatively low risk areas, its application is certainly questionable to high risk areas such as the Gulf of Alaska. These comments have been replete with references to the CEQ report, the NAS critique, Environmental Protection Agency misgivings and the warnings of the National Oceanic and Atmospheric Administration that sufficient information on the Gulf of Alaska does not exist. The chairman of the Council on Environmental Quality, as previously noted, has recommended that Gulf drilling be deferred until improvements in technology are accomplished in less hazardous areas. Alternative (D) provides the focal point for the recommendations of most government agencies and concerned private organizations toward drilling in the Gulf of Alaska. It should not be dismissed in four sentences of unsupported conclusory statements.

Pages 339-340

We have previously discussed the role of baseline and special studies in BLM's decision-making process. These comments adequately cover the alternative mentioned in subsection (D)(1)(b). For point

of clarity, however, it might be noted that the discussion provided in subsection (D)(1)(b) contradicts statements made in the impact statement, particularly the one noted earlier that "baseline studies must precede leasing for validity." It is also noted on page 324 of Volume II of the statement:

> "Decisions on whether to hold lease sales in any area will not be made until the completion of all necessary studies of the environmental impact and the holding of public hearings. Environmental, technical, and economic studies may effect decisions not to hold any given sale."

This is in flat contradiction with the text on pages 339-340. We strongly recommend that the Department of Interior hold true to its earlier statement, and not hold any lease sales, or take any other action which might compel the implementation of the leasing program in any particular region, until baseline and special studies are complete. In the Gulf of Alaska, this will take several years.

Page 341

The Department summarily dismisses the option of deferring leasing until coastal states have sufficient time to develop approvable coastal zone management plans pursuant to the Coastal Zone Management Act of 1972. In earlier sections of these comments, we have detailed the potential impacts of Outer Continental Shelf development on the coastal zone of Alaska. These impacts will be immense. As previously noted. Louisiana, which did not have the benefit of coastal zone planning prior to the onslaught of OCS development in that area, has been severely impacted by the loss of wetlands associated with refineries, pipelines and other onshore facilities.

Moreover, the net costs of the coastal states of onshore development will also be significant. Texas has estimated that it will cost that State $62 million per year to provide public services for onshore facilities. 139/ Alaska officials have estimated that, in light of an acknowledged lack of infrastructure and existing facilities, net yearly costs to the State of Alaska will run in excess of $390 million per year if development proceeds in all Alaska OCS regions. 140/ The State thus agrees with Monte Canfield of the General Accounting Office that both the letter and spirit of the Coastal Zone Management Act of 1972 dictate that this massive Federal action be postponed until the State is capable of coping with the potentially devastating impacts which in the past have invariably ensued from OCS development:

> "It seems to me that the kind of analysis expected to be undertaken under the Coastal Zone Management Act of 1972 and the National Environmental Policy Act of 1969 are precisely the kinds of analysis which must be made if intelligent decisions are to be made regarding OCS leasing... let's assume that such analysis could be done in a reasonable period of time, let's say one or two years...I would argue that the burden of proof must rest on those who would proceed with immediate leasing without the benefit of such analyses." 141/ Similarly, the National Academy of Sciences recommended: "The Coastal Zone Management Act, the only existing mechanism for comprehensive national coastal protection, should be strengthened and fully funded to encourage the development of coastal zone management

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139/ "Benefits and Costs to State and Local Governments in Texas Resulting From Offshore Petroleum Leases on Federal Lands, Management Science Division, Office of Information Services, Office of the Governor, November 1974.

140/ State of Alaska, Department of Natural Resources, Energy Resources staff material, January 1975.

141/ NOPS SoCal Hearings at 47.

plans and regulations...no OCS leasing should occur until after the development of adequate coastal zone plans." 142/

The role of the Coastal Zone Management Act in the cushioning and channeling of onshore impacts was described by Dr. Robert M. White, administrator of NOAA:

"The potential for all types of impacts are now materially heightened by the rapid rate of expension (of OCS leasing) that is being called for. The kinds of problems that were encountered in the past will be encountered more frequently because of the more intense present and future competition of uses of the coastal zone.

"If I were to single out an event which more than any other placed us in a position to provide the necessary rationale and balanced management of this new enterprise, it would be the passage in 1972 of the Coastal Zone Management Act. That Act now provides us with a means of establishing, with the cooperation of the coastal States, a suitable management system." 143/

The Department of Interior has consistently opposed a delay of leasing pending preparation of State coastal zone management plans for no reason other than the fact of delay itself. Department officials summarily rejected this alternative in the NOPS hearings, giving the reasoning quite succinctly:

"If the Department should halt drafting the EIS at this time and wait for adoption of the Coastal Zone Plan, a sale could not be held before late 1976 or 1977." 144/

It is not necessary in these comments to dwell in detail on the critical resource allocation problems which gave rise to the

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142/ OCS and the Coastal Zone at 33.
143/ NOPS Hearings at 93.
144/ NOPS SoCal Hearings at 47.

Coastal Zone Management Act of 1972. Even without Outer Continental Shelf leasing, the demands upon a state's coastal zone are immense, and the ability of that zone to withstand the demands upon it are uniquely limited. The State of Alaska is urgently attempting to acquire the means to effectively plan the future of its coastal zone. Section 307 of the Coastal Zone Management Act contains a provision for federal consistency with the plan--that is, it is the intent of Congress that the Federal government not frustrate this critical planning process. Outer Continental Shelf oil drilling represents the most significant federal action which will affect the State's coastal zone, at least in the foreseeable future. To plunge ahead with such a program, insensitive to the State's needs to manage and control the precious and fragile resources of the coastal zone, frustrates the purpose of the Coastal Zone Management Act.

The Department of Interior has, in the past, paid little attention to the various coastal states' efforts in their development of available coastal zone mangement plan. The National Ocean Policy Study notes that Interior officials possess little familiarity with the Coastal Zone Mangement Act, and have give the Act little or no functional role in the development of the accelerated OCS leasing program. The State of California has complained vigoriously that the Bureau of Land Management has failed to coordinate its Southern California program with that state's Coastal Zone Conservation Commission. Indeed, William E. Grant, Manager of the Pacific OCS OFfice, conceded to the California legislature that, "I am not familiar with this (the Coastal Zone Management) act." 146/ Unfortunately, a similar lack of federal-state coordination has developed in Alaska.

146/ California Select Committee on Coastal Zone Resources, Hearings on Offshore Oil Drilling, April 9, 1974 at 49.

In sum, the potential onshore impacts of Outer Continental Shelf oil development--impacts which have been consistently minimized in the impact statement--are immense. Estuaries and wetlands will be lost by pipeline dredging, onshore facilities siting and the like; public service costs running into the hundreds of millions of dollars may be visited upon the State; the tranquil rural character of many small coastal villages will be forever lost; and coastal-dependent industries, such as fisheries, recreation and tourism, will be permanently compromised. At the present time, states share neither in the formulation of the program nor in the financial benefits of it. Coordination--that is, meaningful coordination, with a substantial degree of state planning leverage--is an absolute pre-requisite to state participation, or even acquiesence, in the expanded OCS program. The Coastal Zone Management Act provides a critical mechanism for accomplishing this goal.

<u>Pages 341-342</u>

As these comments have noted, severe criticisms of BLM's and UGSGS' managerial role over Outer Continental Shelf oil leasing have been leveled both by other federal government agencies, and the private sector. These criticisms must be dealt with in the EIS and necessary corrections taken before the initiation of the program. Otherwise, there is a substantial probability that adverse environmental impacts will be heightened. In the statement, the reviewing public is simply not made aware of what steps are being taken by the Bureau of Land Management and U.S. Geological Survey to improve its management and supervisory deficiencies, and thus, cannot effectively gauge the magnitude of the impacts of the proposed action. A more definitive response to these criticisms is certainly called for in the final environmental impact statement.

Pages 345-346

Again, the discussion of a possible discontinuance of OCS leasing is of little analytical value, since the impact statement has failed to demonstrate what role existing or expanded OCS leasing will have in meeting both regional and national energy demands. This alternative must be thoroughly discussed and analyzed with reference to the cost/benefit analysis which the final environmental impact statement should provide on the proposed program itself. The environmental impacts of OCS leasing discontinuance likewise cannot be gauged. The Council of Environmental Quality, in its April, 1974 report, provided a preliminary matrix of the relative environmental costs of various energy sources. That report found that there would not be substantial differences in terms of environmental impacts between OCS leasing and increased reliance on certain other energy sources--particularly coal. 147/ A more comprehensive matrix, comparing the various environmental impacts of alternative energy sources, should be provided in the final environmental impact statement.

Pages 347-409

Before proceeding into a discussion of the various energy alternatives themselves, we would recommend that an additional energy alternative be included in the final environmental impact statement--that is, increased resource potential from accelerated secondary and tertiary recovery processes. The environmental impacts of secondary and tertiary recovery techniques would be significantly less than those involved in expansion in frontier areas. Admittedly, profits derived from secondary and tertiary recovery may not be as great as for expansion

147/ CEQ Report at 3-28--3-44.

in new areas. However, BLM must constantly keep in mind that it is the public interest which it must serve in administering public lands, and not simply that of the oil industry.

A major criticism of Section F is that it does not address itself to the pertinent question: Are there energy alternatives which could be utilized in the new future, and what effect would these alternatives have on the immediate needs of the nation to develop the petroleum resources of the Outer Continental Shelves? Most of the section merely contains descriptions of alternative energy systems without investigating what it all in terms of being able to reduce the nation's almost total dependency on oil and gas for energy.

There is no discussion of economics, very little discussion of real potential of alternate energy, only present development trends, etc. For example, the AEC has issued growth forecasts for nuclear power which are neatly shown in the statement--but how does this relate to OCS leasing? Presumably a higher growth of nuclear power would alleviate stresses of OCS leasing, but how much and how many more environmental problems would be caused by increased nuclear power capacity compared to diminished OCS leasing? Would the trade off be worth it? It seems that these types of questions are fairly pertinent to any environmental analysis of energy alternatives.

The following sections contain a quick analysis of each energy alternative as contained in DES 74-90; they include:

1. A review of material presented in DES 74-90.
2. Alaska's potential for contributing to alternate energy potential. (Unfortunately Alaska could rely 100% on alternative energy sources, export all of its oil and gas and

and still not affect the national situation to any degree. Alaskan energy consumption in 1971 was only 31 million BOE per year, compared to 2,012 million BOE per year for the 12 western states. (Wilkinson, 1974))

3. Due to the small effect Alaska will have on the nation (with regard to alternative energy only), whenever possible the effect of using and developing alternate energy sources within the Western United States was also considered.

Our conclusion is that there are energy alternatives which can be utilized in the near term to alleviate the pressures of massive and hasty campaign to develop, produce and deplete domestic oil and gas resources on the OCS without regard to long-term conservation concepts. A few of these alternatives are available now or will be in the near future and will probably cause comparatively few environmental problems. A number of other alternatives are readily available, but there is a question whether environmental problems created would be more pronounced or less pronounced than developing the OCS. Some alternatives have serious technologic, economic or environmental problems which will have to be overcome before they can be considered as viable alternatives. It is our opinion that in the western United States, the combination of energy conservation, greater onshore exploration, rational utilization of hydroelectric energy and development of geothermal energy could not only provide more energy in the new term than OCS leasing on the west coast and Alaska but may be able to do so at less environmental, technological, and economic costs. However, it should be noted that further detailed studies should be undertaken by the Federal Government immediatly to evaluate these alternatives and that this analysis only concerns the western states.

The EIS does not emphasize sufficiently the large amount of energy which can be saved using the energy conservation alternative. For example, if a 20% savings in total energy consumption could be effected for the next 10 years in the U.S., the total savings by 1985 would be 35 billion BOE (Barrel of Oil Equivalent), a figure which is over 30% of the total estimated recoverable oil and gas resources of the entire Alaskan OCS, and almost double the total estimated recoverable resource base for the Gulf of Alaska OCS. 148/

I. Alaska's Potential

Potential for conservation in Alaska is probably less than in many other areas becuase of low population and due to the climate, better insulated buildings. However, a 20% reduction of energy consumption in Alaska by 1985 would probably conserve more than 9 million BOE per year.

II. Western U.S. Potential

Projected energy use for the 13 western states in 1985 is a 8.7 million BOE per day. A 20% reduction would result in a daily saving of 1.75 million BOE.

III. Summary and Conclusions

Energy conservation is the best short and long term answer to the energy problems of this country. A 20% reduction of energy use would entail much less personal sacrifice than most people realize (most of it could be accounted for in better insulation, smaller, lighter cars, lowered speed limits, more efficient appliances, etc.). If energy consumption was cut by 20% over the next 10 years an amount would be saved equal to 30% of the total estimated Alaska

OCS recoverable oil and gas resources and double the Gulf of Alaska OCS resources. Other alternative energy sources are analyzed as follows:

148/ Alaska Division of Geological and Geophysical Surveys, 1974, Energy Resources of Alaska: Oil and Gas; Open File Report #50.

A. INCREASED HYDROELECTRIC POWER

This section of DES 74-90 fails to fully and clearly explain the impact of hydroelectric power on the energy problem. A great number of percentages are cited but only tend to be confusing. No comparison between the amount of energy that could be contributed by hydroelectric sources and that expected from the development of the Outer Continental Shelf is made.

I. Alaskan Potential

If the development rate increases, Alaska may be able to supply 172 billion kilowatt hours per year in the long term and 131.8 billion per year in the near future. 149/ The short term potential amounts to .613 million BOE per day.

II. Western U.S. Poetential

Only 30% of the nation's hydroelectric potential is being used at this time. Most of the undeveloped resources are in the Western States. Western hydroelectric power development may supply as much as 191.2 billion kilowatt hours per year by 1985. 150 This is equivalent to .89 million BOE per day.

III. Summary and Conclusions

Adding the potential energy contributions that may be expected by 1985 from Alaska and the Western States, we obtain a figure of 1.5 million BOE per day. The demand for electricity in the Western States may reach 3.8 million BOE per day by 1985. 151/ If the hydroelectric resources are developed as expected the Western States (including

Alaska) may be able to supply about 39% of the anticipated electricity demand.

Unfortunately, it is difficult to transport electricity over great distances. Unless Alaska is "plugged" into the nation's power grid, the electricity generated from her waters will have to remain in the State (16% of projected western demand). The Western States could supply 23% of their projected electricity demand by 1985.

149/ "Energy from Falling Water" Energy Perspectives, No. 14, Spet. 1974

150/ Energy Resource Development for the West, page 20.

151/ Ibid, page 4.

B. GEOTHERMAL

The conclusion of this section on page 415 of DES 74-90 that within 20 years geothermal energy may account for only 1 or 2 percent of total U.S. energy needs is inconsistent with many other projections. This is discussed further in the following sections.

I. Alaskan Potential

Alaska has a large potential for utilization of geothermal energy. IT has been estimated that the State's geothermal resources may contain the energy equivalent of 500 billion barrels of oil assuming hot dry rock systems to be technically exploitable. However, since utilitzation of this energy in Alaska would make only a very small overall energy saving to the U.S. as a whole (Alaska consumed only 31 million BOE of energy in 1971 (Wilkinson, 1974), the problem becomes one of transporting this energy to the lower 48 and overcoming the technical problems concerned with hot dry rock exploitation. The only way to transport Alaska geothermal is to convert it to electricity and connect it to the U.S. power grid through overhead transmission lines or some other method. For the short term (Gulf of Alaska oil could be on stream between 1980-85) it appears that the technologic and environmental problems associated with utilizing and transporting Alaskan geothermal resources would probably have little appreciable effect on the energy problems of the U.S. However, for the long term and for the State of Alaska's ability to supply its citizens with the energy they need (no matter how much oil and gas this State has

it will be required to participate in any shortages suffered by the rest of the U. S.), an immediate program of research and development must be initiated within the State to guarantee the people a long term supply of energy at reasonable costs. This program should be funded by non-renewable energy revenues now so that when our non-renewable resource base is exhausted we have a viable alternative.

II. Western U. S. Potential

It has been estimated that in 1985 energy consumption of the 12 western states will be 8.7 million BOE per day (Wilkinson, 1974). In a statement to the Senate Committee on Interior and Insular Affairs (Serial No. 93-3 part 2, page 709), John Nassikas, Chairman of the Federal Power Commission estimated that with proper incentives the potential of geothermal energy could be almost 4.25 million BOE by 1985. (By contrast, it would probably take the immediate discovery of Prudhoe Bay type reserves in the Gulf of Alaska to be producing one-half million barrels of oil per day by 1985.) 4.25 million BOE per day would be almost 50% of the total energy consumption of the 12 western states in 1985, and would definitely constitute more than 1 or 2 per cent of total U. S. energy demands as stated in DES 74-90. Also, the indiginous energy (geothermal) would supply the western states (most of the geothermal potential of the U. S. lies in the west) and free other forms of energy to be exported east. It should be emphasized that the above figures are based on assumed potential, not present development trends. Thus, realization of the above potential would depend on a large influx of capital both from government and industry, a highly motivated and well funded research and development program by the Federal government, a much more enlighted leasing program for geothermal resources on

public land and probable incentives such as a depletion allowance to allow new technologies and advance theories to be tested by industry for practical development.

III. Summary and Conclusions

Production and conversion of geothermal heat to electricity represents by far the least detrimental method in regard to adverse environmental impact if one considers the total fuel cycle and also energy production. For example, when the effects of a nuclear power station are considered, one has to also consider the environmental impact of strip mining the uranium ore, refining the ore, enriching the ore, and transporting the final product to the station (all of which, incidentally, consume large amounts of energy in themselves. For every 1,000 BTU's of delivered energy from a nuclear fission (LWR) plant, 664 BTU's are used to manufacture that energy. For every 1,000 BTU's of delivered energy from dry steam geothermal sources, only 99 BTU's are used to manufacture that energy.) 152/

Therefore, from an environmental, energy saving, and economic (for a discussion of the economics of geothermal energy utilization, see Tsai Meidav, 1974), point of view, the immediate development of the U. S. geothermal resource base could have a significant impact on the massive campaign to develop U. S. oil and gas resources at a rate which in the final long term analysis may prove to be of more harm than good. Substituting a depletable domestic resource for a depletable foreign resource merely substitutes one source of instability for another, unless those resources are used for a transition to a permanently sustainable domestic resource base. The only way to accomplish this is to use each resource conservatively for what it is best suited. In the long term, using oil and gas to

produce electricity is not only wasteful, but it may prove disastrous to those segments of the economy which can use only oil and gas. Geothermal energy is uniquely suited to electrical energy production (amoung other things) and should be utilized as soon as possible.

152/ Testimony by the Oregon Office of Energy Research and Planning, September 18, 1974.

C. INCREASED ONSHORE PRODUCTION

Gas: The statement indicates that "Conventional gas supplies are expected to decline despite U.S. estimated gas potential" (Page 356). This is a curious statement. Why, with good potential, will supplies decline? The answer lies in the regulated price of gas. (Converting to BOE and assuming $0.42 per mcf for gas and $10.00 per barrel of oil: One BOE of oil is now $10.00. One BOE of gas $2.27. Even if $7.00 per barrel is a more realistic price, the price of gas is a tremendous bargain and this has led to its popularity with users and its unpopularity with resource suppliers. The net result is that, by deregulating the price of gas, exploration and, therefore, supplies should increase by a large but undetermined amount by 1985 and should be closer to Case IV on Page 355 of DES 74-90 than any of the others.

Petroleum Liquids: The forecast of onshore petroleum supplies on Page 356 is completely inadequate. First of all, the estimates were probably made in 1972 before the large price increase in oil and, secondly, it includes expected offshore production which doesn't make sense since one is presumably comparing offshore production with onshore. For Alaska alone, the table doesn't take into account future discoveries near Prudhoe Bay, NPR-4 development, Native development and possibly State Tidelands if environmental considerations permit development. The increased price of oil has stepped up exploration in the lower 48 to the limit of available drilling rigs and shows no signs of stopping. All these factors will combine to increase domestic onshore reserves, probably far in excess of what was predicted in 1972.

I. Alaska's Potential

The combination of further development of Prudhoe Bay, Beaufort Tidelands (if environmental considerations permit development), NPR-4

exploration on Native lands, and further development of State and Federal lands make onshore Alaska a prime area for discovering onshore reserves. The State of Alaska Geological and Geophysical Surveys have estimated the potential resources of onshore Alaska as 26 billion barrels of oil and 95 trillion cubic feet of gas. The State also regards onshore development as major actions, which require thorough planning and evaluation of the social, economic, and evironmental risks, before proceeding.

II. Western U.S. Potential

The potential for increasing onshore production in the Western U.S. is largely unknown. The price increases in oil have stimulated exploration to the limit of available rigs and will make previously uneconomic secondary and tertiary recovery systems economic. Also, low producing stripper wells previously uneconomic may be rejuvinated or will continue to produce. California is probably in a mature state of exploration, but the Rockies are in a youthful stage. The chances of finding any giant oil fields are considered small, but still possible. Thus, production will surely increase, but this may not be enough to offset declining production in known areas.

III. Summary and Conclusions

Increased onshore oil and gas production may be a very viable energy alternative. The situation is better than shown in DES 74-90 and, if gas prices are deregulated, the situation will be very good. More time has to be spent on determining just how much this increase is going to amount to over the next 10 years in the entire country, in order to make meaningful comparisons.

D. INCREASED USE OF COAL

The statement fails to indicate the possible near-future contribution of coal. It merely states the reserves of low-sufur coal in the United States and the expected production by 1980 given current economic and technological conditions. A more complete approach would be to assume that coal could be developed to its full potential by improving coal economics. This is a possibility if the U.S. could refuse to develop its domestic oil and gas resources and put a stop on all foreign imports for energy generation.

I. Alaskan Potential

According to a recent (and as of this time unpublished) report by the DGGS, Alaska may contain as much as 133 billion tons of low-sulfur coal reserves. 153/ The 70 billion tons quoted in DES 74-90 seems to be somewhat pessimistic. The amount of coal in Alaska is equivalent to about 458.6 billion BOE. This is 27.6 times the amount of energy thought to be in the Gulf of Alaska Outer Continental Shelf.

II. Western U.S. Potential

According to DES 74-90, reserves of low-sulfur coal in the western states amount to 70 billion tons. This quantity of coal is equivalent to 241.4 billion BOE. Compared with the Gulf of Alaska oil and gas resources of 16.6 billion BOE of available energy, we find that the energy contained in western coal reserves is 14.5 times that contained in Gulf of Alaska petroleum resources.

By 1982, coal-fired electricity generation may require 100 million tons of coal per year for plants which are planned for the near future or are already under construction. 154/ If plant construction and coal production were increased to attempt to meet

growing energy needs, we may anticipate a need of up to 200 million tons of low-sulfur coal per year. At that consumption rate, the 70 billion tons of western coal would last for 350 years producing 1.89 million BOE's of available energy per day. By 1985, with maximum development, the Gulf of Alaska may produce 109.5 million BOE per year, 3 million BOE per day.

III. Summary and Conclusions

Coal reserves in the western states are enormous and could serve as an important source of energy in the future if environmental difficulties are overcome and production could be drastically increased. This is much easier said than done, especially in Alaska where support facilities, and infrastructure are at a primitive stage of development, and development problems are magnified by the inhospitable environment. Thorough environmental analysis would have to be done before exploration.

To increase coal production would require huge capital investments to produce the additional necessary equipment and open new mines. Several techniques for cleaning coal of pollutants are currently being investigated, but a crash program of research would have to be started if we are to expect coal to become more important as a near term source of energy. If coal could be used in greater amounts for electricity generation, oil and gas that is currently being used in that capacity could be released for other uses for which there are no substituties, such as production of synthetics, etc.

153/ Open File Report #51 Mineral Resources of Alaska and the Impact of Federal Land Policies on Their Availability - Coal. By McGee, D.L. and O'Connor, K.M. In press.

154/ The Independent Coal Miner, Vol. 17, No. 1, Spetember 1973.

E. INCREASED NUCLEAR CAPACITY

There is very little to review in this section since there was no analysis of the consequences of increased nuclear power capacity. How much could the capacity be increased? Would this make a significant dent in energy needs? Are there raw materials available to build the plants? What would this do to uranium reserves? Would we have to import uranium? Would enrichment facilities be able to handle increased loads? Would increased environmental problems be worth the effort? These are but a few of the questions which need to be answered, not only about nuclear power but about all energy alternatives.

I. Alaskan Potential

The potential for nuclear power to make any significant contribution to Alaskan power needs is probably small for the near and far terms. Hydroelectric and hopefully geothermal power alone can probably suppy Alaska's needs into the foreseeable future with much less adverse environmental impact. However, Alaska does contain potential for containing significant amounts of uranium, and if nuclear power development continues at the pace projected, possible exploitation of this valuable resource in the State may be of some importance insofar as development in Alaska itself is concerned.

II. Western U.S. Potential

The Western United States contains close to 25% of the world uranium reserves and its electrical demand is such that increased nuclear power production is already planned. Therefore, an increase in power plant construction would have significant effects to the west in terms of increased mining pressures and depletion of uranium reserves. Doubling of planned reactor capacity could add .420 million

BOE per day by 1985. This still constitutes only 11% of projected electric demand for the western states by 1985.

III. Summary and Conclusions

The DES 74-90 contains forecasts for nuclear power growth, but what does this mean with regard to increased oil leasing, particularly leasing in Alaska? Increased nuclear power development would lessen the immediate need for development on the OCS. However, this would increase exploitation of uranium (which could significantly affect Alaska if uranium reserves are discovered) and would increase the environmental and technical problems from which the nuclear power industry is suffering today. In summary, this resource could be expanded to help alleviate extraction from the OCS, the question is, is the environmental and technological tradeoff worth it?

F. SOLAR ENERGY

DES 74-90 discussion of solar energy is greatly lacking in detailed information. There is no mention of actual costs of any of the various conversion methods mentioned in the text and the uses are not discussed in enough detail. How much land would have to be covered by solar cells to produce a certain amount of electricity? How much energy could be saved by a house heated and cooled by solar energy? The statement failed to discuss at least three indirect methods of harnessing solar power -- wind, ocean currents and biological photosynthesis. 155/ Each different form should have been discussed and evaluated as to cost, environmental impact, technology and eventual contribution to the energy crisis.

I. Alaskan Potential

Alaska does not possess a large potential for direct uses of solar energy. Over most of the State, there isn't enough direct sunlight for an adequate length of time to warrant the use of solar cells or thermal systems to produce electricity for either single residences or on a larger scale for whole cities. Residential solar heating and cooling systems have a low potential for use in the 49th State also. In the Aleutians, there is a large potential for using wind energy to generate electricity for local communities, although methods need to be perfected to store the electricity over calm days. Any attempt to use ocean currents will necessitate construction of extremely strong undersea "wind-mills" to withstand severe storms.

II. Western U.S. Potential

States in the more southern section of the U.S. have a better chance of using solar energy to produce electricity directly or heat

and cool their homes and businesses due to a more appropriate climate. Wind, ocean thermal gradients, ocean currents, and biological photosynthesis all have good potentials for use in the western states if technologies could be developed to store the energy to provide the heat for bioconversion of wastes is particularly attractive proposition.

III. Summary and Conclusions

The use of solar energy would require many changes but could contribute a significant amount to the energy shortage. At this time, solar energy is more expensive than oil and gas, but it is quickly becoming more comparable in price. It appears now that the best uses of the sun may be in heating and cooling private homes and businesses. This alone could constitute a great savings of petroleum products. Converting waste to methane and oil would be advantageous in two ways: (1) It would help solve waste disposal problems; and (2) it would result in useful energy products. This process has been used successfully in Chicago and Los Angeles but technical problems remain to be solved before it can be used on a large scale.

155/ Alternative Energy Sources
Energy Perspectives, "Energy from the Sun - Part One", Issue No. 12, July 1974.

G. SYNTHETIC NATURAL GAS AND OIL PRODUCTION

This section of DES 74-90 discusses only above-ground processing of coal and petroleum and neglects in-situ conversion of coal. No comparison of available energy was made between that which could be supplied by coal and natural petroleum. The possibility of air pollution is reduced by coal conversion because sulfur and particulates are removed during the process.

I. Alaskan Potential

Alaska contains enormous coal resources, much of which might be converted to gas and oil. 156/ A study is necessary to compare the economic and environmental aspects of mining the coal and processing it within the State versus exporting the raw coal to refineries in the continental United States. In-situ processing would have the least environmental impact and is especially applicable to much of the coal in Alaska. The amount of energy in Alaskan coal and the need for environmental analysis prior to exploration was discussed earlier in the section entitled "Increased Use of Coal."

II. Western U.S. Potential

The 70 billion tons of low sulfur coal reserves and much of the other coal in the western states could be used for conversion to gas and liquid hydrocarbons.

III. Summary and Conclusions

Converting oil to gas seems to be a waste of energy. Oil can be used for other things besides the production of gas. Importing oil and natural gas for feedstocks defeats the whole purpose of Project Independence and should not be considered as a viable alternative. If enough incentive could be supplied, coal gasification and liquification could be important contributions to the energy supply. An increase in coal production would require

large amounts of capital, an increase in the production of iron ore and other metals for the manufacture of equipment. Techniques for in-situ processing and land reclamation should be encouraged. A plant is in operation in the U.S.S.R. which is extracting low-BTU gas from burning coal in the ground and using the gas to generate electricity. The process has proved to be economically feasible. Techniques are in the pilot plant stage which allow the refinement of coal into petroleum products that could replace natural oil and gas. A combination of the Solvent Refined Coal and Bi-Gas processes has been proposed which would result in a synthetic natural gas, propane, fuel oil, and solvent refined coal (which can be burned to generate electricity). Sulfur and other pollutants are extracted during the process and become valuable by-products.

156/ Alaska Division of Geological and Geophysical Surveys Open File Report #51

H. OIL SHALE PRODUCTION

Again, DES 74-90 fails to compare the amounts of energy that could potentially be supplied by oil shale with OCS development. The statement also makes no mention of the quantity of resources or reserves; it merely mentions that "Oil shale occurs in large volumes throughout the U.S. and potentially could contribute significantly to U.S. energy supplies." (DES 74-90, page 399). This section also lacks any conclusions. The environmental aspects are discussed adequately.

I. Alaskan Potential

Alaska's oil shale potential is thought to be quite large, but so far only minor studies have been made and the data is unavailable at this time.

II. Western U.S. Potential

The U.S. has an oil shale potential of over 2 trillion BOE and the western states contain most of that amount. 157/ Project Independence calls for production of at least 500,000 BOE per day by 1980. That would amount to 182.5 million BOE per year. At that rate, U.S. reserves could supply energy for approximately 11,000 years. Note that the Alaskan Gulf of Alaska OCS will probably supply 109.5 million BOE per year with a total resource of 16.6 billion BOE.

III. Summary and Conclusions

Although the oil shale potential is large, there are extreme environmental problems associated with its production that may well over-shadow its benefits. The most environmentally sound method with which to mine oil shale is in-situ; that is, actually extracting the oil from the shale while it is still in the ground.

Some success has been achieved in combining underground mining and in-situ retorting. If more lucrative incentives were offered, perhaps this method would find more commercial use in the near future. Oil shale petroleum can only marginally compete economically with conventional petroleum at current prices.

157/ Alternate Energy Sources, op. cit.

Pages 410 - 413

As these comments have mentioned previously, the gap in public availability of necessary geological and geophsycial information severely compromises the ability of both the Federal government and the public to weigh the costs and benefits of OCS leasing in particular regions. The Federal government must largely rely on the representations of the oil industry itself--a reliance unwillingly shared by the reviewing public. The lack of necessary geological and geophysical data is critical and certainly commands more attention than the summary rejection of a Federal exploratory program given on page 412:

> "About the only advantage that a Federal Exploratory Drilling Program would be the added knowledge the Government would receive, and perhaps could better evaluate the hydrocarbon resources to be leased,".

In rejecting a Federal exploratory program, the Department states that "industry would also do its normal exploration and research resulting in duplication of effort." Certainly this need not be the case. The government's geological and geophysical information would become publicly available and would tend to reduce the need for a subsequent comprehensive exploratory drilling effort by industry. Clearly, the public interest would be better served by a leasing program which allows both the Federal government and the public to be fully apprised of the resource potential of a particular frontier area prior to any commitment to lease.

Pages 414 - 416

The State of Alaska's primary criticism of the bonus bidding system is that, with such a large capital investment at the outset,

the practicability of closing an area to leasing, or severely constricting operations due to subsequently disclosed environmental hazards, is significantly lessened. The vested interest of the oil industry simply become too great.

Page 421

The State of Alaska would suggest that the potential for conflict of interest and the need for objectivity in the EIS is not "mitigated by the wide distribution of impact statements for Federal, State, and public review and comment." The Department is well aware of the substantial discretion and latitude that the authoring agency has in the structuring and content of the environmental impact statement. The "arbitary and capricious" standard makes the EIS well-nigh substantively invulnerable.

The Department of the Interior must consider that the program they are proposing is much more than a simple dam building or highway project. Its implications extend to all coastal states and cross the jurisdiction of a plenthora of Federal agencies. It is perhaps the most significant major Federal action affecting the quality of the human environment that has been undertaken by a Federal agency. The need for this interagency coordination and, indeed, authority is critical in the OCS leasing program. The State would recommend that the impact statements for accelerated Outer Continental Shelf oil leasing be written by the National Oceanic and Atmospheric Administration which is itself conducting much of the necessary baseline efforts in conjunction with the National Academy of Sciences and the Environmental Protection Agency. The impact statement should then be subject to review and approval by the President's Council on Environmental Quality. The need for checks

and balances in the present program are hard to overestimate. At the outset of these comments, the State referred to public statements made by Interior officials which underscored the apparent foregone nature of the program. Credibility, again, is indeed a critical issue in this particular debate. The State of Alaska believes that the Council on Environmental Quality's April 1974 report was a far superior environmental analysis of the proposed program than is DES 74-90. Agencies, such as CEQ, should continue their efforts, and those efforts should have substantive value in the future shaping of the program.

The impact statement omits several critical managerial alternatives. Several major alternatives are listed for inclusion in a revised draft EIS which we suggest is needed:

1. Deferring of any expanded OCS leasing activity until Congress has acted upon a revenue sharing measure to more appropriately allocate the costs and benefits of the program.

2. The abandonment of the "leasing" system for OCS oil and gas exploration and substitution of a licensing system would require the developer to disclose his full development plans, both offshore and onshore, prior to the award of the license. The license would be granted to the developer who had demonstrated the best environmental control technology and best advanced planning for cushioning and channeling potential impacts. This system has been recommended by the University of Oklahoma report, and the State concurs that it holds great promise for OCS oil and gas operations.

3. Revisions should be considered to the OCS Lands Act which would provide for more efficient and meaningful enforment of statutes, regulations, orders and development plans. Specifically, an admin-

istrative fine system should be established, without a required showing of "wilfulness" for liability, and its imposition should be mandatory for any violation of OCS orders, regulations, or other requirements.

4. In addition, the Department should recommend legislation which would give coastal states a veto power over OCS oil development off their coasts.

Pages 425 - 426

The National Environmental Policy Act imposes on each Federal agency the burden of considering social and environmental factors in reaching decisions, as well as technical and economic facts. Of course, it is not an absolute requirement that environmental factors override other common and more traditional decision-making criteria. However, the analysis must, at least, be made, and the costs and benefits weighed before one interest is allowed to override the other

In that light, the State is particularly distressed by the unsupported conclusion of the impact statement that requiring utilization of the best demonstrated environmental control technology will not be mandated by the Department on the Outer Continental Shelf because of the talisman of "economy." There is no analysis, that is, no discussion of the relative benefits to be gained, versus the economic costs to be incurred in requiring more sophisticated technology; simply a deference to the oil industry in their efforts to maximize profits. Not only is this conclusion in obvious violation of NEPA, it also rejects application of the Federal Water Pollution Control Acts Amendments of 1972 to Outer Continental Shelf oil drilling. It impeaches without discussion draft new source and best available control technology standards under con-

sideration by the Environmental Protection Agency. On a large scale, it underscores the apparent view of the Bureau of Land Management towards the Outer Continental Shelf, that is, that its chief value is as a resource pool for oil and gas, and not as a long term storehouse for renewable resources and a sanctuary for our natural heritage.

In response, the State would concur with the National Academy of Sciences in the following statement:

> "The CEQ report does not describe incremental costs of various applications of current technology to environmental protection. We conclude that such data will be useful and hope that such a study will be initiated. We recognize that, in some instances, the cost of safe operation of environmental controls may increase the cost of extraction beyond the level at which operations are economically attractive. In such a case, resources should be developed elsewhere under circumstances where total costs, with environmental costs properly taken into account, are less. Importantly, the fact that environmental controls in such a case are costly should not be used as grounds for reducing the level of control, but rather should indicate that the development of that resource should be deferred to a time when the costs of environmental control are reduced through technological advances or the value of the resource increases."

CEQ Report at NAS-32.

In conclusion the draft environmental impact statement is seriously flawed. It provides no information for the public or the State to evaluate the soundness of the program. In its present form it in no way complies with the requirements of NEPA and it seems to be in violation of other Federal statutes such as the Endangered Species Act. In order to provide the public with a true opportunity to review Federal decision-making related to this major project, the draft should be rewritten and then circulated again as a draft.

ATTACHMENT H

ANALYSIS
OF DRAFT ENVIRONMENTAL IMPACT STATEMENT
REGARDING "PROPOSED INCREASE IN
ACREAGE TO BE OFFERED FOR OIL AND
GAS LEASING ON THE OUTER CONTINENTAL SHELF"

Presented on Behalf of the Southern California Council of Local Governments Concerned With The Federal Proposal for Accelerated OCS Oil & Gas Development

Prepared and Submitted on Behalf of the Southern California Council of Local Governments

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THE SOUTHERN CALIFORNIA COUNCIL OF LOCAL GOVERNMENTS CONCERNED WITH THE FEDERAL GOVERNMENT'S PROPOSAL FOR ACCELERATED OCS OIL & GAS DEVELOPMENT

The Southern California Council of Local Governments Concerned with the Federal Proposal for Accelerated OCS Oil & Gas Development was formed by a group of Mayors, Councilpersons and other governmental officials. The purpose of this Council was to discuss the proposals of the Department of the Interior in regard to expanded OCS development.

The members of the Council, each of which intend to testify as part of the testimony presented by the Council at the hearings, include:

City of Los Angeles
City of San Diego
County of San Diego
City of Beverly Hills
City of Santa Monica
City of Santa Barbara
County of Santa Barbara
City of Riverside
City of Newport Beach
City of Torrance
City of Palos Verdes Estates

City of Rancho Palos Verdes

City of Laguna Beach

County of Orange

City of Huntington Beach

Southern California Association of Governments

Due to the press of time, this Analysis could not be fully circulated to all members of the Council to receive formal ratification. As of the date of printing, however, the following jurisdictions have formally authorized submission of this Analysis on behalf of their jurisdictions:

City of Los Angeles

City of San Diego

City of Santa Monica

City of Riverside

City of Torrance

City of Palos Verdes Estates

City of Laguna Beach

County of San Diego

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Section II

SCIENTIFIC ADVISORY COMMITTEE REPORTS

Summary of Analysis of Draft Environmental Statement Regarding "Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf"

The following is a summary of the detailed Analysis of the Draft Programmatic E.I.S. on expanded Outer Continental Shelf (O.C.S.) Drilling prepared by the Bureau of Land Management (B.L.M.). This Analysis has been prepared by and on behalf of the Council of Local Governments Concerned with O.C.S. Development, for presentation to B.L.M. as a portion of the comment and input to be given by the participating jurisdictions during the public hearing and review process.

The Analysis is based upon a comprehensive review of the E.I.S., the Project Independence Blueprint, and over sixty major documents dealing with energy and O.C.S. development. Included in the Analysis is a critique of the E.I.S. prepared by the Scientific Advisory Committee. That Committee was formed, at the request of the Council, to advise the participating jurisdictions as to the accuracy of the data included in the E.I.S., the additional data which should be provided, the additional scientific studies which should be undertaken, and related matters

I. Requirements for Legally Adequate E.I.S.

The specific requirements regulating the nature and content of the Draft E.I.S. are set forth and established by the National Environmental Policy Act (N.E.P.A.), the Guidelines for Implementation of N.E.P.A. promulgated by the President's Council on Environmental Quality (C.E.Q.), and by the case law interpreting these foregoing provisions. Having carefully reviewed the draft E.I.S. in light of these legal requirements, we have concluded that the draft E.I.S. is seriously inadequate and fails to fulfill the legal mandate that it set forth a "detailed statement of the environmental impact of a project and the project's alternatives."

Specifically, the E.I.S. fails to:

(1) Adequately discuss the relationship between the proposed O.C.S. development and the establishment of a comprehensive national energy policy, with proper reference to the Project Independence Blueprint, as required by law;

(2) Adequately discuss our principal energy alternatives, including most importantly the alternative of energy conservation;

(3) Develop the data on marine resources necessary to an intelligent analysis of the impact of O.C.S. development upon those resources;

(4) Provide a detailed analysis of the primary, secondary, and cumulative effects of O.C.S. development, supported by empirical data or scientific authorities; and

(5) Address the numerous major issues discussed in this Analysis.

II. Inadequacies of the E.I.S.

A. O.C.S. Development as an Integral Part of a National Energy Policy:

Any decision made in regard to O.C.S. development clearly must be made in the context of a comprehensive national energy policy. In that regard, the adequacy of the E.I.S. is severely impaired due to the fact that its completion preceded release of the Project Independence Blueprint. The failure of the E.I.S. to fully consider and weigh the alternatives suggested in the Project Independence Blueprint, and the failure of the E.I.S. to clearly measure the proposed O.C.S. development program in the context of a national energy program, is violative of both the spirit and express requirements of the law.

B. The Need for O.C.S. Development Has Not Been Adequately Demonstrated:

The E.I.S. only refers to the demand projections of the National Petroleum Council, the Ford Foundation Energy Report, and Department of the Interior's own demand projections. There is no reference to the Project Independence Blueprint demand projections. Further, the Department of the Interior's own projections of a 2% to 3% increase in energy growth over the next 25 years is little more than a rough guess of what future energy demands might be. It does not provide a valid basis for a decision regarding greatly expanded O.C.S. development.

We submit that the most useful demand projections are those in the Ford Foundation Energy Report. This Report projects three different scenarios: (1) a historical growth scenario, (2) a technical fix scenario, and (3) a zero energy growth scenario. Even under the historical growth scenario of a 3.4% energy growth rate, the greatly accelerated O.C.S. program now being contemplated by the Interior would not be necessary. Additionally, under either the technical fix scenario or the zero energy growth scenario, O.C.S. development would not be necessary in the time frame now being considered.

The Project Independence Blueprint, which the draft E.I.S. fails to consider, assumes that there will be no significant O.C.S. development in the Pacific, Atlantic or Gulf of Alaska areas. Moreover, a report from the House Committee on

Interior and Insular Affairs, entitled The Trans-Alaska Pipeline and West Coast Petroleum Supply, 1977-1982, indicates that there will be a surplus of petroleum supplies during the period 1977-1982 in the Pacific region. These factors must be considered by the Department of Interior in making any decision to lease in the Pacific, Atlantic, or Gulf of Alaska.

C. The Alternative of Energy Conservation:

A mandatory energy conservation program offers a viable alternative to accelerated O.C.S. development. This alternative was not adequately evaluated by the E.I.S.

Accelerated development of all our energy sources will still not meet unrestrained demand. Economic as well as environmental factors mandate that we adopt a strong energy conservation plan. We suggest that serious consideration must be given in the E.I.S. to the following energy conservation alternatives discussed at much greater length in the Analysis:

1. Transportation:

The Project Independence Blueprint suggests a number of means to greatly increase use of public transit, thereby reducing our national dependence upon the automobile. Additionally, it has been suggested that tax incentives should be developed to encourage automakers to produce more energy efficient cars which are lighter, and have better aerodynamic designs. A tax might be levied on cars not meeting improved fuel economy standards.

2. Building and Urban Design Proposals:

Space conditioning presently accounts for more than 60% of residential energy use. This use can be substantially reduced by requiring better insulation and by modifying building design. The nation's building codes must be updated. The Federal Housing Authority should revise their standards for issuing loans by requiring a life-cycle cost for building designs. Subsidies and guaranteed loans should be provided so that lower income families can increase the energy efficiency of their homes. Over the life-cycle of a house, the cost of improving the energy efficiency of the structure is far outweighed by savings on fuel costs. There are numerous tax incentive programs which can be suggested to improve construction practices.

3. Industry:

Industry consumption accounts for 33% of the total U.S. energy demand. Energy efficiency can be increased in almost all industries by implementing a program designed to promote: (a) better maintenance of existing equipment; (b) recovery of process heat losses; (c) modifying product specifications to minimize consumption patterns; (d) shifting from use of raw materials which require high energy consumption; (e) using natural fertilizers as substitutes for petroleum and natural gas intensive fertilizers; and (f) using recycled materials.

4. <u>Natural Gas</u>:

Continuous use of gas pilot-lights is responsible for consumption of an estimated 223-billion cubic feet of gas annually in the United States. A long-range cost/benefit analysis to the consumer indicates that substituting electric starters for gas pilots is economically justified and would result in substantial energy savings.

5. <u>Lighting</u>:

Lighting accounts for 25% of U.S. electricity consumption. Much of that is used wastefully in decorative or advertising lighting or as a result of over-illumination and should be more stringently regulated.

6. <u>Heating, Cooling and Ventilating Systems</u>:

Approximately 18% of the total national energy consumption is for heating buildings. Much of the energy used in adjusting internal temperatures would not be necessary if buildings were properly insulated and designed. Energy consumption in buildings may be reduced by: (a) use of solar or solar-assisted heating and cooling; (b) heat pumps; (c) rockbed regenerators; and (d) by adopting building codes requiring energy-conserving techniques.

7. Research and Development:

Our nation has failed to make a reasonable allocation of research and development funds between our various energy alternatives, including conservation. Substantial funds should be allotted for development of: (a) heat transfer technology; (b) low temperature heat applications; (c) energy savings in space conditioning; (d) industrial steam production technology; (e) integrated power generation; (f) improvements in efficiency of power generation; and (g) new manufacturing processes.

In summary, the Analysis points out that the E.I.S. completely fails to consider one of the principal alternatives to O.C.S. development -- a mandatory national energy conservation program. The experience of the City of Los Angeles during last Fall's energy crisis proves the value of mandatory energy conservation programs. During the winter of 1973-74, the City of Los Angeles implemented a plan which resulted in a 17% reduction in energy use during the first two months the program was in effect. A study of the results of that plan by Rand Corporation indicates that: (1) lighting changes accounted for most of the reduced use; (2) most business establishments regarded 20% as a reasonable amount to cut without adverse consequences to business; and (3) most businesses are continuing to maintain the reductions they made during that period. The Analysis concludes that with economically and technologically feasible energy conservation practices, our energy growth rate can easily be reduced to 2% annually, and even zero energy growth is possible. Unfortunately,

the E.I.S. fails to give this alternative the serious attention it warrants.

D. Other Energy Alternatives:

The E.I.S. discusses several suggested energy alternatives to O.C.S. drilling. However, the treatment of those discussed is clearly inadequate, while other significant alternatives are simply not discussed.

Among the alternatives cursorily examined in the E.I.S. and which are treated at much greater length in this Analysis are solar, geothermal, nuclear, oil shale, hydroelectric and oil importation. The alternatives not discussed in the E.I.S. but considered in this Analysis include bio-energy, wind, and secondary and tertiary recovery from existing wells. Bio-energy we especially feel is advantageous because it supplies energy while solving solid waste management problems. Secondary and tertiary recovery are also sound resource management tools which deserve greater attention. In summary, the treatment of other energy alternatives in the E.I.S. is seriously deficient.

E. Production of Shut-In Wells and Secondary and Tertiary Recovery as Alternatives to Expanded O.C.S. Development:

No mention in the E.I.S. is made of the alternatives to O.C.S. development of production of wells now apparently "shut-in" in the Gulf of Mexico, nor is there an adequate consideration

of the alternative of secondary and tertiary recovery from existing wells. The House Sub-Committee on Regulatory Agencies has found that a substantial number of tracts capable of production in the Gulf of Mexico have been classified as shut-ins by the U.S. Geological Survey upon the request of oil and gas companies. The Federal Power Commission has made similar findings regarding the production capacity of oil and gas fields. The question is whether or not classification of a tract as shut-in is appropriate. Substantial evidence seems to indicate that in many cases it is not.

The House Sub-Committee has found that the Department of the Interior has not demonstrated its capacity to efficiently administer the present leasing system. If this is true, what is the justification for greatly accelerated O.C.S. development under the same regulatory system? Whether shut-ins are the result of inadequate manpower and materials, or a desire of the oil companies to develop the areas in the future when prices are higher, the fact remains that the nation appears to have presently leased areas capable of production which are not now producing.

The same concern is applicable to the failure of the E.I.S. adequately to discuss the production capacity which would result in secondary and tertiary recovery. Adequate recovery is not being undertaken at this time because the oil companies apparently do not find it to be economically attractive. Nonetheless, these national resources which have already been tapped should not be left partially developed if they can be fully developed in an environmentally and economically sound manner.

F. The Elk Hills Example of Present Onshore Potential:

The E.I.S. entirely ignores one of the most feasible alternatives to accelerated O.C.S. development, that is the tapping of existing onshore petroleum reserves held by the military. One particular example not even mentioned in the E.I.S. is the Elk Hills Naval Petroleum Reserve. Within 18 months, 230,000 barrels-a-day could be produced from Elk Hills, with maximum production of 350,000 barrels-a-day being reached within 3 years -- well ahead of what can reasonably be anticipated from newly leased O.C.S. areas.

The cost of developing Elk Hills, as opposed to O.C.S. development cost, is dramatic. While offshore wells cost up to $2 million each to drill, with offshore platforms costing as much as $30 million, onshore wells drilled at Elk Hills are normally a fraction of this cost.

Substantial evidence indicates that the Elk Hills Naval Reserve is not necessary for national defense. The President has now indicated that he supports opening this Naval Reserve for domestic consumption. Clearly, it is an example of a meaningful onshore alternative which should have been discussed in the E.I.S.

G. Substantial Evidence Indicates that O.C.S. Development Cannot be Undertaken Within the Time-Frame Proposed

The E.I.S. only superficially discusses the serious problem of the ability of the oil industry to keep production abreast with the proposed increase in leasing due to the major

shortages of drilling rigs, equipment and skilled manpower. The findings of two major federal Congressional reports, and the Blueprint for Project Independence, convincingly demonstrates that the leases now proposed for development could not be developed within the proposed time-frame. Further, both the report of the Ad Hoc Committee on the Domestic and International Monetary Effect of Energy and Other National Resources Pricing of the House Banking and Currency Committee, and the report from the National Oceans Policy Study on Outer Continental Shelf Oil and Gas Development in the Coastal Zones, raise serious questions about the viability of accelerated O.C.S. leasing in light of current shortages of equipment, construction materials, and trained personnel. The Project Independence Blueprint indicates that shortages in drilling rigs, tubular goods, and walking draglines cannot be overcome in the short-run period. Even a technical paper released by the Department of the Interior indicates a severe shortage of these necessary materials. In summary, the E.I.S. fails to deal with this significant issue, that is whether accelerated O.C.S. development is in fact a meaningful solution or viable alternative.

H. Mitigation Measures Not Adequately Considered

The E.I.S. fails to consider measures which would mitigate the potential adverse environmental effects of O.C.S. development. The E.I.S. should at the very least consider the following possible mitigation measures:

1. Immediate exploration of the potential lease areas so we would know what is in fact available;

2. Establishing a priority system so that lease sales would first take place in the areas farthest offshore with the least potential environmental impacts;
3. Camouflaging rigs to preserve aesthetic values;
4. Requiring subsea completion of wells to preserve aesthetic values, and reduce navigational obstructions;
5. Establish more stringent drilling and production regulations.

I. Failure to Consider Relative Environmental Impacts

The relative environmental impacts of drilling throughout the O.C.S. must be evaluated prior to any further lease sales. This evaluation was not provided for by the E.I.S.

A report entitled O.C.S. Oil and Gas - An Environmental Assessment, prepared by the President's Council on Environmental Quality, demonstrates that such an analysis is possible. Although limited to the Atlantic coast and the Gulf of Alaska, the C.E.Q. report resulted in a rating of various possible development areas according to environmental sensitivity and resource potential. Southern California has certain unique resources, as do other areas, and efforts must be made to evaluate the impact of O.C.S. development on those resources. In summary, in order for the E.I.S. to be legally adequate, it is submitted that the relative environmental impacts of drilling in various areas throughout the O.C.S. must be developed and discussed.

J. <u>Insufficient Data for Environmental Analysis</u>:

The E.I.S. is replete with admissions that sufficient data is not available regarding marine and coastal resources or the impact of O.C.S. development on those resources. The E.I.S. includes nineteen such major admissions of lack of data. Even though the drafters of this Analysis had extremely limited time and personnel, in all but five of the specific areas involved, we found literature sources providing the necessary analysis. In those areas where data is not now available, the Department of the Interior has an affirmative obligation to develop the necessary data.

One example of the need for additional data is provided by the report of the Southern California Academy of Sciences. This group is presently under contract with the Bureau of Land Management to provide baseline data on the Southern California marine resources. Although the Department of the Interior contends that this baseline data is only needed for monitoring of O.C.S. development, rather than for making the determination as to whether there should be such development in the first instance, it is important to note those specific areas where the scientific community believes additional data is necessary. Thus, the Southern California Academy of Sciences concluded:

1. Geological oceanography, especially in regard to seismic activities off Southern California, is inadequate. Recommendations for numerous studies were made.

2. Additional studies of vertebrate and invertebrate populations, habitats and sevsitivity to oil pollution need to be studied.

3. A better understanding of physical oceanography, including oceanographic and surface meteorology, is needed.

4. A better understanding of chemical oceanography is needed.

K. Degradation of Air Quality:

The E.I.S. only provides a discussion of possible degradation of air quality in terms of the result of evaporation from oil spills. N.E.P.A., however, requires a discussion of both the primary and the secondary impact of a project. Obviously, the onshore activity which is the consequence of O.C.S. development will have a substantial adverse effect on air quality.

Increased refinery capacity and operation will clearly result in substantial increases in sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide and hydrocarbons. The air quality in Southern California is far from reaching primary ambient air quality standards set pursuant to the Federal Clean Air Act. Further degradation in air quality will result from increased refinery capacity. This issue should be fully addressed by the E.I.S.

L. The Onshore Land Use Impacts of O.C.S. Development:

The discussion of onshore impacts within the E.I.S. is wholly inadequate. Among the more notable onshore activities having significant primary land-use impacts are the following: (1) harbor and dock facilities; (2) equipment storing areas; (3) pipeline terminals and corridors; (4) tank farms and transportation facilities; and (5) refinery, petrochemical complexes, and supporting construction industries. The potential of these facilities for conflicting with other land-use values, and the resulting environmental impacts, must be fully discussed and considered by the E.I.S.

M. The Santa Barbara Oil Spill -- An Impact Never Discussed:

The E.I.S. never discusses the Santa Barbara oil spill, despite the fact that it is an incident that exemplifies many of the economic and environmental consequences of O.C.S. development. The 1969 blowout from a major channel platform was the result of poor operating procedures and government regulations. Over 3,250,000 gallons of oil spilled into the ocean, resulting in a slick of over a thousand square miles. Over 80 miles of coastline were contaminated. Containment and recovery efforts were woefully inadequate.

Although long-term effects of the Santa Barbara spill on the marine and coastal environment are difficult to estimate,

they clearly are substantial. As to short term damages, the cost of replacing dead organisms has been estimated to be over $10 million. Over $10 million was spent by the oil companies for control and cleanup, and approximately $640,000 by governmental agencies' post spill operations. Indirect costs of the spill include diminution of property values and loss of tax revenues. Short term loss to the commercial fishing industry was over $800,000. Loss in recreational value has been estimated to be over $3 million.

The E.I.S. makes no attempt to estimate these very real costs which may result from O.C.S. development, nor is the entire subject of potential impacts from spills or accidents meaningfully developed.

N. <u>Diminution of Property Values</u>:

The E.I.S. fails to discuss the diminution of property values that will result from O.C.S. development. The potential adverse impact upon land values of the aesthetic blight of platforms and potential for oil spills is well demonstrated by the Santa Barbara case. Total diminution of property values resulting from the Santa Barbara oil spill ranged from a total of $6,885,000 to a high of $8,934,000. Potential adverse impacts of these magnitudes must be discussed by the E.I.S.

Q. Economic and Resource Losses to State and Local Governments Resulting From O.C.S. Development:

The E.I.S. does not discuss possible adverse economic consequences to local governments resulting from O.C.S. development, nor does the E.I.S. discuss the loss to the public of visual amenities, beach and marine resources and recreational values. Studies from both Louisiana and Texas indicate that local government, in providing services to O.C.S.-related developments, bear substantial economic burdens. The public at the same time suffers a substantial loss of its beach and marine resources.

III. Economic Analysis of the Federal Leasing System

The E.I.S. entirely fails to consider the relative economic merits of alternative leasing systems. This is contrary to the mandate of N.E.P.A. that environmental as well as economic and technical cost benefits analyses must be prepared. With the exception of one trial royalty-fixed cash bonus system, the federal government is now operating under a cash bonus-fixed royalty system which combines an initial substantial cash payment with a fixed royalty established by the Secretary of the Interior based upon the estimated value of leased lands.

The problems resulting from the current system include:

(1) A serious dampening effect on competition; and

(2) Huge vertically-integrated petroleum companies dominate the bidding.

Additionally under the current system, it appears that the Department of the Interior's regulation of leasing schedules is inadequate. As a result, areas may be developed either too quickly or too slowly. Oil drilled in the mid-1980's is now being sold for 1975 prices.

There are at least ten alternative leasing systems (4 royalty systems, 4 rental systems, and 2 profit sharing systems) which deserve serious examination and consideration, including:

1. Fixed royalty/bonus bidding;
2. Fixed bonus/royalty bidding;
3. Royalty schedule decreasing overtime;
4. Two-parameters royalty schedule;
5. Rental payments/bonus bidding;
6. Fixed bonus/rental bidding;
7. Oil pledge/bonus bidding;
8. Fixed bonus/oil pledge bidding;
9. Fixed profit share/bonus bidding;
10. Fixed bonus/profit sharebidding.

In brief, the O.C.S. oil reserves belong to the American people. Before they are leased, it is essential that all principal leasing systems are fully evaluated and considered to ensure that the federal government provides for the most responsible and economically sound protection of our interests.

IV. Procedures for Evaluation

The procedures followed by the Department of the Interior for evaluation of lease sales does not ensure a systematic reasoned decisionmaking process. The procedures for public participation in the hearing process hampers full public participation. The Department of Defense excludes areas from consideration for lease sales, on the basis of national security, in a manner that prevents review of the decisionmaking process. As a result of those exclusions, other areas may be selected for leasing which may be more environmentally sensitive.

V. Substantial Evidence Exists to Indicate That a Determination to Drill Has Already Been Made

Statements from high ranking officials in the Department of the Interior indicate a commitment to O.C.S. development. The refusal of the Department of the Interior to await establishment of a national energy policy, and the refusal to postpone designations until after an adequate final program E.I.S. is considered in the decision making process, indicates that the E.I.S. is only a post hoc rationalization for a decision which has already been made.

VI. The Federal Coastal Zone Management Act

The Department of the Interior's plans to proceed with O.C.S. leasing prior to the completion of coastal zone management plans by impacted states circumvents the purposes of the 1972 Coastal Zone Management Act. O.C.S. leasing should be postponed until such time as the states have had an opportunity to adopt coastal zone management plans and have such plans approved by the U.S. Secretary of Commerce, as provided for in the Coastal Zone Management Act. Once such approval is obtained, any federal agency conducting or supporting an activity directly affecting the coastal zone shall, to the maximum extent practicable, conduct such activities consistent with approved management programs.

The energy element of California's coastal plan adopted by the Coastal Commission on January 23, 1975, proposes for California the policy that new offshore oil and gas development shall be permitted only after: (1) the need for petroleum has been clearly established in light of anticipated flows to California from the Alaska north slope and other production sources, and consideration is given to California's capacity to refine and store anticipated inflows; or (2) development of the O.C.S. off California has been clearly identified as an integral and priority part of a comprehensive balanced national energy conservation and development program. Other policies in the energy element adopted by the Coastal Commission include: (1) allowing offshore drilling

only where safe; (2) encouraging consolidation of drilling production and processing sites; (3) requiring the use of submerged completion and production systems where feasible and environmentally safe; (4) minimizing the impact of onshore facilities; (5) establishing an oil spill liability fund; and (6) protecting against any adverse impact of O.C.S. development by seeking an agreement with the Department of the Interior that no federal leases be approved until the Department of the Interior makes a commitment to undertake a comprehensive environmental protection plan in regard to O.C.S. development. The policy recommendations of the California Coastal Zone Conservation Commission have evolved out of a long planning process. The Department of the Interior should not be allowed to circumvent the purposes of the Federal Coastal Zone Management Act by ignoring the position of the California Coastal Zone Conservation Commission in regard to O.C.S. development.

I. STATEMENT OF INTEREST

Concern regarding the Department of the Interior's proposals for expanded Outer Continental Shelf (hereinafter referred to as O.C.S.) development has been so great that for one of the first times in history local governments have joined together in an attempt to present a coordinated response to a federal program. A Council of Mayors, Councilmen and Councilwomen, and Supervisors has been meeting continually in order to assess the actions of the Department of the Interior and to prepare such a response.

Those governmental entities which have participated in the Council are not representing only coastal interests. Many inland cities and counties have also participated on the Council. Moreover, in view of the fact that over 75% of the people live in the 30 coastal states, a desire to protect our coastal resources can hardly be deemed to be "parochial." Most importantly, however, we view our role in commenting upon the program Environmental Impact Statement (hereinafter referred to as E.I.S.) as raising questions of national interest in the wise utilization of our nation's natural resources.

II THE REQUIREMENTS FOR A LEGALLY ADEQUATE E.I.S.

N.E.P.A. mandates all agencies of the Federal Government to

> Identify and develop methods and procedures, . . . which shall ensure that presently unquantified environmental amenities and values may be given appropriate consideration in decisionmaking along with economic and technical considerations. . . 42 U.S.C., §102.1(b).

Moreover, Congress has established that it is the national policy to

> (5) Achieve a balance between population and resource use which will permit high standards of living and a wide sharing of life's amenities; and (6) enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources. 72 U.S.C., §101(b).

The draft E.I.S. has failed to quantify environmental amenities. The purpose of N.E.P.A. to assure wise use of our national resources has not been furthered by the draft E.I.S. The specific inadequacies of the E.I.S. result from its failure to:

1. Adequately discuss the relationship between establishment of a national energy policy, with proper reference to the <u>Project Independence Blueprint</u>, and O.C.S. development.

2. Adequately discuss our energy alternatives, including the alternative of conservation.

3. Develop the data on marine resources necessary to an analysis of what impact O.C.S. development would have on those resources.

4. Provide a detailed, rather than a conclusory analysis of the primary, secondary, and cumulative effects of O.C.S. development.

5. Address the numerous major issues discussed in the following analysis.

It is the responsibility of every federal agency undertaking major federal actions which may significantly affect the environment to carefully comply with the procedural requirements of N.E.P.A. These procedural provisions are not highly flexible. As stated in Calvert Cliffs Coordinating Committee v United States AEC, 449 F. 2d 1109 (D.C. Cir. 1971), the E.I.S. procedures establish a strict standard of compliance. As the Court of Appeals in that case stated:

> The sort of consideration of environmental values which N.E.P.A. compels is clarified in section 102(2)(a)and (b). In general, all agencies must use a 'systematic, interdisciplinary approach' to environmental planning and evaluation 'in decisionmaking which may have

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an impact on man's environment.' In order to include all possible environmental factors in the decisional equation, agencies must 'identify and develop methods and procedures * * * which will ensure that presently unquantified environmental amenities and values may be given appropriate consideration in decision-making along with economic and technical considerations.' 'Environmental amenities' will often be in conflict with 'economic and technical considerations.' To 'consider' the former 'along with' the latter must involve a balancing process. In some instances environmental costs may outweigh economic and technical benefits and in many other instances they may not. But N.E.P.A. mandates a rather finely tuned and 'systematic' balancing analysis in each instance.

To ensure that the balancing analysis is carried out and given full effect, section 102(2)(c) requires that responsible officials of all agencies prepare a 'detailed statement' covering the impact of particular actions on the environment, the environmental costs which might be avoided, and alternative measures which might alter the cost-benefit equation. The apparent purpose of the 'detailed statement' is to aid in the agencies' own decisionmaking process and to advise other interested agencies and the public of the environmental consequences of planned federal action. Beyond the 'detailed statement', section 102(2)(d) requires all agencies specifically to 'study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources.' This requirement, like the 'detailed statement' requirement, seeks to ensure that each agency decisionmaker has before him and takes into proper account all possible approaches to a particular project (including total abandonment of the project) which would alter the environmental impact and the cost-benefit balance. Only in that fashion is it likely that the most intelligent, optimally beneficial decision will ultimately be made. Moreover, by compelling a formal 'detailed statement' and a description of alternatives, N.E.P.A. provides evidence that the mandated

> decisionmaking process has in fact taken place and, most importantly, allows those removed from the initial process to evaluate and balance the factors on their own.

The draft E.I.S. is not a detailed cost-benefit analysis. The issue is whether it is legally adequate.

The basic criteron for establishing whether an E.I.S. is legally adequate is full disclosure of the possible consequences of an action:

> At the very least N.E.P.A. is an environmental full disclosure law. . . the detailed statement required by section 102(2)(c) should, at a minimum contain such information as will alert the President, the Council on Environmental Quality, the public, and indeed, Congress, to all known possible environmental consequences of proposed agency action. Environmental Defense Fund v Corps of Engineers, 325 F. Supp. 728, 759 (E.D. Ark. 1971), aff'd, 478 F. 2d 289 (8 Cir. 1972).

In the E.D.F. case, supra, the court turned to the dictionary definition of "detail" and concluded that "Necessarily, the E.I.S. must be 'marked by abundant detail or thoroughness in treating small items or parts'." In discussing the need to balance complete disclosure against limitations on information which is available, the court stated:

> In reviewing the sufficiency of an agency's compliance with section 102, we do not fathom the phrase 'to the fullest extent possible' to be an absolute term requiring perfection.

If perfection were the standard, compliance would necessitate the accumulation of the sum total of scientific knowledge of the environmental elements affected by a proposal. It is unreasonable to impute to the Congress such an edict. We preface our consideration of plaintiffs' contentions by declaring that the phrase 'to the fullest extent possible' clearly imposes a standard of environmental management requiring nothing less than comprehensive and objective treatment by the responsible agency. . . Thus, an agency's consideration of environmental matters that is merely partial or performed in a superficial manner does not satisfy the requisite standard.
EDF v Corp of Engineers, supra, p.

Although the statement must be detailed, it must in is case address the broad policy issues of the program to pand O.C.S. development. The requirement for a program E.I.S., dressing broad policy issues is set forth in the C.E.Q. idelines for implementation of N.E.P.A.:

"In many cases, broad program statements will be required in order to assess the environmental effects of a number of individual actions in the given geographical area (e.g. coal leases) or environmental impacts that are generic or common to a series of agency actions (e.g., maintenance or waste handling), or the overall impact of a large-scale program or chain of a contemplated project (e.g., major links of highways as opposed to small segments). Subsequent statements on major individual actions will be necessary for such actions which have significant environmental effects not adequately evaluated in the program statement." 40 CFR §1500.6(6)(1), 38 Fed. Reg. 20552 [August 1, 1973].

The decision of the U.S. Court of Appeals for the strict of Columbia in the case of Scientists' Institute for blic Information vs. A.E.C., 481 F. 2d 1079, 1086-88 (D.C. rcuit 1973), clearly sets forth the requirement for a 'ogram E.I.S. on an issue as complex as O.C.S. development.

"The Commission takes an unnecessarily crabbed approach in assuming that the impact statement process was designed only for particular facilities other than for analysis of the overall effects of broad agency programs. Indeed, quite the contrary is true.

Individual actions that are related either geographically or as logical parts in a chain of contemplated actions may be appropriately evaluated in a single program statement. Such a statement also appears appropriate in connection with . . . development of a new program that contemplates a number of subsequent actions. . . [T]he program statement has a number of advantages. It provides an occasion for a more exhaustive consideration of effects and alternatives than would be practicable in a statement on an individual action. It ensures consideration of cumulative impacts that might be slighted in a case-by-case analysis. And it avoids duplicative reconsideration of a basic policy question.

The statutory phrase 'actions significantly affecting the quality of the environment' is intentionally broad, reflecting The Act's attempt to promote an across-the-board adjustment in federal agency decision-making so as to make the quality of the environment a concern of every federal agency. The legislative history of The Act indicates that the term 'actions' refers not only to construction of particular facilities, but includes 'project proposals, proposals for new legislation, regulations, policy statements, or expansion or revision of ongoing programs. . .' Thus, there is 'Federal Action' within the meaning of the statute not only when an agency proposes to build a facility itself, but also whenever an agency makes a decision which permits action by other parties which will affect the quality of the environment." <u>Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Com'n supra, pp 1086-88</u> [footnotes omitted].

After careful review of the entire E.I.S. and the Project Independence Blueprint, we are particularly concerned that the E.I.S. does not provide for balanced, systematic, and reasoned decisionmaking in regard to O.C.S. development as one aspect of the establishment of a national energy policy. The Project Independence Blueprint is only superficially referenced in the Program E.I.S., despite the requirement stated in the Council on Environmental Quality Guidelines for implementation of N.E.P.A. that "The interrationships and cumulative environmental impacts of the proposed action and other related federal projects shall be presented in the statement." 40 C.F.R. §§1500.8 (a)(1).

Also required to be included is a statement of:

> (6) The relationship between local short-term uses of man's environment and the maintenance and enhancement of long term productivity.
> (7) Any irreversible and irretrievable commitments of resources that would be involved

in the proposed action should it be implemented. (8) An indication of what other interests and considerations of Federal policy are thought to offset the adverse environmental effects of the proposed action identified pursuant to paragraphs (a)(3) and (5) of this section. The statement should also indicate the extent to which these stated countervailing benefits could be realized by following reasonable alternatives to the proposed action (as identified in paragraph (a)(4) of this section) that would avoid some or all of the adverse environmental effects. In this connection, agencies that prepare cost-benefit analyses of proposed actions should attach such analyses, or summaries thereof, to the environmental impact statement, and should clearly indicate the extent to which environmental costs have not been reflected in such analyses. §1500.8 (5) (Emphasis added)

The program E.I.S. fails to address these broad policy issues.

The role of O.C.S. development in our total energy picture is never clearly enunciated in the E.I.S. This is undoubtedly partially attributable to the fact that the Project Independence Blueprint was not released until after the release of the E.I.S. Such an analysis is crucial if there is to be compliance with N.E.P.A.

To attempt to make a decision on accelerated O.C.S. development without first determining what action may be taken pursuant to the Project Independence Blueprint is to attempt to make a major federal policy decision in a vacuum.

The fact that the Department of the Interior is proceeding with a schedule for tract specific E.I.S.'s and lease sales indicates that the program E.I.S. and the Project Independence Blueprint will not be considered in the manner required by N.E.P.A. Although the requirement that environmental factors be considered is stated in N.E.P.A. explicitly only once, it

has been well-established since Calvert Cliffs Coordinating Committee, 449 F. 2d 1109 (D.C. Cir. 1971), that implicit in all section 102 requirements is the concept that agencies are obligated to consider in good faith the environmental information which they have developed. Judge Wright's summary of the purposes of N.E.P.A. is perhaps one of the best judicial statements of the "consideration" requirement.

> "N.E.P.A., first of all, makes environmental protection a part of the mandate of every federal agency and department. The Atomic Energy Commission, for example, had continually asserted, prior to N.E.P.A., that it had no statutory authority to concern itself with the adverse environment effects of its actions. Now, its hands are no longer tied. It is not only permitted, but compelled, to take environmental values into account. Perhaps the greatest importance of N.E.P.A. is to require the Atomic Energy Commission and other agencies to consider environmental issues just as they consider other matters within their mandates. This compulsion is most plainly stated in Section 102. There, 'Congress authorized and directs that, to the fullest extent possible:
>
> (1) the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this Act* * *.' Congress also 'authorizes and directs' that '(2) all agencies of the Federal Government shall' follow certain rigorous procedures in considering environmental values. Senator Jackson, N.E.P.A.'s principal sponsor, stated that '[n]o agency will [now] be able to maintain that it has no mandate or no requirement to consider the environmental consequences of its actions.' He characterized the requirements of Section 102 as 'action-forcing' and stated that '[o]therwise, these lofty declarations [in Section 101] are nothing more than that.'

> "The sort of consideration of environmental values which N.E.P.A. compels is clarified in Section 102(2) (a) and (b). In general, all agencies must use a 'systematic, interdisciplinary approach' to environmental planning and evaluation' in decisionmaking which may have an impact on man's environment.' In order to include all possible environmental factors in the decisional equation, agencies must 'identify and develop methods and procedures * * * which will insure that presently unquantified environmental amenities and values may be given appropriate consideration in decisionmaking along with economic and technical considerations.' "Environmental amenities will often be in conflict with 'economic and technical considerations.' To 'consider' the former 'along with' the latter must involve a balancing process. In some instances environmental costs may outweigh economic and technical benefits and in other instances they may not. But N.E.P.A. mandates a rather finely tuned and 'systematic' balancing analysis in each instance." Calvert Cliffs', supra, pp. 1112-13 (footnotes omitted, emphasis added).

As stated by Frederick Anderson in N.E.P.A. in the Courts (Environmental Law Institute 1973): "A statement's adequacy, in the end, is measured by its functional usefulness in decisionmaking. The statement must be of a nature and a form that enables the decisionmaker to consider environmental factors in good faith". Both the timing and the content of this program E.I.S. leads us to the conclusion that it will not aid in the type of systematic and reasoned decisionmaking in regard to establishment of a national energy policy required by N.E.P.A. It is for those reasons legally inadequate.

The discussion of energy alternatives is also inadequate. An E.I.S. must include:

(4) Alternatives to the proposed action, including, where relevant, those not within the existing authority of the responsible agency. (section 102(2)(d) of The Act requires the responsible agency to 'study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflict concerning alternative uses of available resources'). A rigorous exploration and objective evaluation of the environmental impacts of all reasonable alternative actions, particularly those that might enhance environmental quality or avoid some or all of the adverse environmental effects, is essential. Sufficient analysis of such alternatives and their environmental benefits, costs and risks should accompany the proposed action through the agency review process in order not to foreclose prematurely options which might enchance environmental quality or have less detrimental effects. §1500.8(4) (emphasis added)

The draft E.I.S. does not provide the required analysis. N.R.D.C. v Morton, 458 F. 2d 827, (D.C. Cir. 1972) is a case specifically addressing the need to discuss energy alternatives to O.C.S. development: "What is required is information sufficient to permit reasoned choice of alternatives so far as environmental aspects are concerned." N.R.D.C. v Morton, supra, at 839.

Other E.I.S.'s have been found to be legally inadequate for providing conclusory and uninformative discussions about the alternatives to the project. See Monroe County Conservation Council v Volpe, 472 F. 2d 963, 697 (2d Cir. 1972).

Although the E.I.S. includes a 35 page discussion of the nation's energy alternatives, we do not believe that the E.I.S. is adequate in its treatment, or provides a basis

for good faith consideration, of those alternatives. "N.E.P.A. requires that an agency must--to the fullest extent possible under its statutory obligations--consider alternatives to its actions which would reduce environmental damage." Calvert Cliffs v AEC, supra, at 1128. In view of our limited energy resources, it is important now, more than ever before, to fully analyze the consequences of our actions.

Inadequate attention is also given to the relationship between O.C.S. development and the coastal zone management plans now being prepared in the impacted states. That there must be such an analysis is also established by the C.E.Q. guidelines which state that the impact statement must include an analysis of "the relationship of the proposed action to land use plans, policies, and controls for the affected area." §1500.8 (a)(2)

In many places throughout the E.I.S., the B.L.M. admits that sufficient data is not available regarding specific environmental impacts. N.E.P.A., however, places an affirmative obligation upon federal agencies to develop the missing data. N.E.P.A.: ". . . makes the completion of an adequate research program a prerequisite to agency action. The adequacy of the research should be judged in light of the scope of the proposed program and to the extent to which existing knowledge raises the possibility of potential adverse environmental effect." E.D.F. v Hardin 325 F. Supp. 1401 at 1403 (D.C. 1971). Substantial evidence already exists to indicate that significant adverse

environmental impacts will result from O.C.S. development. B.L.M. cannot rely on the absence of available data to conclude that a resource may not be impacted. The proposed action is far too significant to proceed without a thorough understanding of its conquences.

Although the E.I.S. is over 1200 pages long, the entire first volume is really a description of the project. The discussion of the effects of the project are sketchy at best, and filled with conclusory statements. Many of the conclusions which have been drawn as to O.C.S. development have not been substantiated with supportive data as required by N.E.P.A. This requirement was articulated by the First Circuit: "A conclusory statement 'unsupported by empirical data, scientific authorities, explanatory information of any kind' (citation omitted) not only fails to crystalize issues but 'affords no basis for a comparison of the problems involved and the alternatives.'" Silva v Lynn, 482 F. 2d 1282, at 1287 (1973).

Whether it be by searching other literature sources or proceeding with gathering baseline data, specific scientific data must be assembled to allow for an intelligent analysis of the impact of O.C.S. development.

We believe that a supplement to the draft E.I.S. is essential to meet the requirement of N.E.P.A. It is important to remember, however, that any addendum to the

E.I.S. will be required to go through the same commenting and review procedures as the original. In the case of N.R.D.C. v Morton, supra, the District Court on remand ruled that the addendum prepared by the Department of the Interior to fill in the gaps in the initial statement could not be considered as part of the final statement without going through the same commenting process as was used in producing the initial statement. A more recent case, which comes to the same conclusion, relying on N.R.D.C., is Why? Assoc. v Burns 372 F. Supp. 223 (D.C. Conn.). There the court stated:

> The requirements of circulation for comment and forwarding for 'front office' review of an E.I.S., supplemental or otherwise, are no mere technicalities. The circulation and review requirements are critical features of N.E.P.A.'s efforts to ensure informed decisionmaking by providing procedural inputs for all responsible points of view on the major environmental consequences of the proposed federal action. Thus, N.E.P.A. requires not only the solicitation of comments, but also the attachment of such comments to the E.I.S. itself, which must accompany the proposal through the federal agency's decisionmaking process."

Cases clearly establish the requirement for a reasonably complete draft E.I.S. Inadequacies may not simply be cured in the final. We have concluded that the draft E.I.S. does not meet the requirements of N.E.P.A.

Major issues which have either been inadequately addressed, or not considered at all, are discussed in the remainder of our analysis.

III INADEQUACIES OF THE E.I.S.

A. Development as an Integral Part of a National Energy Policy

Our nation is in the midst of formulating a national energy policy. For too long we have drifted, like a ship without a captain, on a course of ever-increasing energy consumption, and with little regard for how legitimate energy demands could be met. We have ignored the social, economic, and environmental impact of pursuing various energy alternatives, and consumed ourselves into a position where we have become heavily dependent upon other nations to supply our energy needs.

As a result of the energy crisis of last fall, a sense of urgency as to our energy policies was finally instilled in our national leaders. On November 7, 1973, former President Nixon gave his "Energy Emergency" message. In that speech he announced Project Independence. The goal of Project Independence was to meet America's energy needs from America's own energy sources by the year 1980. Although the goal of Project Independence is now open to question and has received widespread criticism, it resulted in a much-needed reevaluation of our energy position and was the first real step toward adoption of a national energy policy.

Our national leadership finally realized that it was crucial to fully explore our energy options. Unfortunately, former President Nixon did not wait for the report on Project

Independence to make a decision as to O.C.S. leasing. On January 23, 1974, he directed the Secretary of the Interior to increase O.C.S. leasing to ten million acres beginning in 1975. Although the announcement was carefully couched in language indicating that such a commitment was contingent upon completion of an environmental evaluation, it became clear that a national commitment to this energy alternative had already been made.

That President Ford is following the same course of action became clear on January 15, when he delivered his Address on the State of the Union. Although that Address was the first step toward formulation of a national energy policy, the message indicated that a decision to expand O.C.S. development had already been made.

As a result of the commitments to O.C.S. development on the part of two national administrations, the program E.I.S. was released prior to completion of the Project Independence Blueprint. Thus, O.C.S. development has not been treated as an integral part of establishment of a national energy policy. We believe that the decision was unwisely made, without a proper evaluation of the myriad of complex associated problems, and in violation of the National Environmental Policy Act.

B. The Need For O.C.S. Development Has Not Been Adequately Demonstrated

The E.I.S. contains only a conclusory, three-page discussion of U.S. energy demand projections. Any federal action taken to open up a resource as precious as the O.C.S. should be based on clearly demonstrated needs. Such an analysis of our country's energy demands is the primary purpose of the Project Independence Blueprint. Despite the fact that Project Independence Blueprint, with its elaborate supply-demand projections, is supposed to represent a comprehensive federal analysis of our energy picture, the E.I.S. does not even refer to Project Independence Blueprint when calculating future energy demands.

Three studies were discussed in the E.I.S.: (1) the National Petroleum Council, (2) the Ford Foundation Energy Report, and (3) the Department of the Interior projections. The basis for the National Petroleum Council's projections for 1971 to 1985 are not stated. A high, intermediate and low projection of annual gains of 4.4%, 4.2% and 3.4%, respectively, are given. Basically, the projections simply continue historical growth rates, taking into account possible reductions due to price increases. The projections represent a continued failure to recognize certain natural limitations on our fossil fuel resources.

The Department of the Interior is in the process of revising its energy forecasts. As stated on p. 152 of the E.I.S.:

> "The original 1972 projection predicted mean annual energy growth rate of 3.6% for the 1971 to 2000 period. However, preliminary indications reveal that the modified forecast will show a lower rate. Considering the three different energy forecasts reviewed above, a guarded estimate of a 2 to 3% increase rate in energy use for the 1971 to 2000 interval appears reasonable. This range is somewhat less than the growth rate experienced between 1950 and 1972 and is significantly less than the rate of increase achieved during the late 1960's and early 1970's. Nevertheless, achieving a 2 to 3% increase in energy growth over the next 25 years will require innovative planning and utilization of our human and technical resources."

The projection above can be treated as little more than a rough "guestimate."The approach is not acceptable when used as the basis for a major federal action significantly affecting the environment such as O.C.S. development.

We submit that the most valid demand projection is that from the Ford Foundation Energy Report. The Ford Foundation Energy Project Report actually projects three different scenarios: (1) a historical growth scenario, (2) a technical fix scenario, and (3) a zero energy growth scenario. Under the historical growth scenario, continued unrestrained demand (except for that resulting from price increases) result in energy use doubling between now and the

year 2000 in residential, commerical and transporation uses, and tripling in industrial uses. This scenario results in a 3.4% energy growth rate. Significantly, energy wasted in the historical growth rate scenario represents about 1/4 of the total energy consumption in the year 2000.

Even under the highest historical growth supply case, domestic oil requirements would be 5.76 billion barrels per year by 1985. If the O.C.S. should supply 20% of these requirements, the total O.C.S. land under lease should be about 21 billion acres in 1985. This could be satisfied by leasing at a rate of 2.5 million acres per year between now and 1985, which is only 1/4 of the rate projected under present policy.

With the technical fix scenario, the annual energy consumption would grow at 1.9 percent per year, a much more manageable growth rate. The technical fix scenario would be achieved entirely by elimination of inefficient energy uses rather than by requiring any substantial changes in our lifestyle.

The most promising scenario, however, in terms of resource preservation is that portrayed in the zero energy growth scenario. Only that scenario can be achieved without placing a tremendous strain on our technology and resources. The zero energy growth scenario is based not only on technological advances but also on a changing,

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Ford Foundation Report, "A Time to Choose", (1974), at 295. Hereinafter cited as <u>Ford Report</u>.

though not less satisfying, lifestyle. Our society would be more service-oriented, with quality, long-lasting goods and greater development of low-energy intensive industries under the zero energy growth scenario. The fringe benefits of this scenario would be less pollution, less congestion, less consumption and perhaps more tranquil lifestyles.

As indicated previously, one would expect that the draft E.I.S. for the proposed O.C.S. development would have discussed the energy projections set forth in the Project Independence Blueprint. The base case projections of U.S. total energy demands in the Project Independence report is a function of the price of petroleum. At $4 per barrel, Project Independence Blueprint projects a 3.8% growth rate while at $7 per barrel oil the growth rate would be 3.2%, and at $11, 2.7%. Of great importance is the fact that the base case forecast was made upon the assumption that there would be no major Pacific, Atlantic or Gulf of Alaska O.C.S. leasing.

As stated above, the E.I.S. treatment of energy demand projections is rather cursory. Not only does it fail to discuss the Project Independence Blueprint, but neither is there any discussion in the section on supply and demand (p.150) of the possible effects which the Trans-Alaskan supply of crude oil may have on the demand projections of the nation. The only reference made to the Alaskan pipeline is found on page 351 of volume 2 of the

draft E.I.S. which states that it:

> " is likely that PAD District V (i.e. the West Coast) will not need significant quantities of petroleum imports in the next decade or so if the Trans-Alaska pipeline is built. After 1985, increased demand may require imports."

This treatment of future Alaskan oil apparently is incorrect. A report, The Trans-Alaska Pipeline and West Coast Petroleum Supply, 1977-1982, prepared at the request of Senator Henry Jackson, Chairman of the Committee on Interior and Insular Affairs (Serial No. 93-51), reveals that

> "Despite the differences in the level of deficit or excess forecast by the various respondents, there is one pattern they have in common: the District V deficit diminishes and/or the excess grows, beginning with the first year of pipeline operation and throughout the entire period. This pattern is quite at odds with the public forecast of industry and administration spokesmen prior to the 1973 passage of the law authorizing construction of the Trans-Alaska Pipeline." (Id. at 14.)

In brief, the projections of two of the three principal owner companies, and of the Department of the Interior, point to an excess of production over consumption in PAD District V beginning 1980, a surplus which apparently "could amount to as much as one billion barrels per day by 1982." Id. at 31.

Thus, not only does it appear that the Alaskan

crude oil will satisfy the demand projections of PAD District V--contrary to the findings in the draft E.I.S--but it will also have an effect on the national energy supply picture. The report reveals that after 1980:

> "[a]ny crude oil that is still imported into the District, therefore, either reduces the District's deficit <u>or</u> increases its exportable surplus by an equivalent volume. Any of the supply from the District, which is 'blacked out' by North Slope oil, would in a similar manner be added to the net supply available in other markets." (*Id.* at 15.)

The chain of events which might follow the exportation of the PAD District V surplus to other PAD Districts is not even considered in the draft E.I.S. Yet future demand predictions go to the heart of accelerated O.C.S. leasing, because the less demand there is for oil and gas, the less necessity there is for an accelerated O.C.S. leasing program.

We submit that the failure to discuss the role of Alaskan oil in connection with future energy demand projections is a serious deficiency of the draft E.I.S. which must be remedied in order to satisfy the requirements of N.E.P.A.

C. The Conservation Alternative

1. The Need for A Conservation Program.

Mandatory energy conservation offers a viable alternative to accelerated development of our limited natural resources. The Federal Energy Agency (hereinafter referred to as the F.E.A.) in its Project Independence Blueprint makes it clear that the goal of "independence" cannot be achieved without an energy conservation program going far beyond any plans thus far proposed by our national administration.[2]

If the present national growth rate of 5% per year continues, then consumption of energy will double by 1990 - only 15 years away.[3] Even if federal leasing of the O.C.S. were allowed, new domestic supplies could not be produced abundantly enough over the next fifteen years to satisfy that increased demand. And with our present rate of consumption, we may exhaust our fossil fuel supplies within 20-50 years, according to estimates set forth in Technology Review, M.I.T. February, 1974.

This nation's energy policy, or the lack of one, is one of the reasons for unabated energy growth. Unfortunately, President Ford has failed to propose a mandatory energy conservation program with a systematic and resourceful use of finite energy supplies. President Ford's State of the Union Message (January 15, 1975) exemplifies that failure. The imposition of higher tariffs on oil imports for the purpose of reducing energy consumption may

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[2] Federal Energy Agency, Washington D.C., Project Independence Blueprint (Nov., 1974). Herein after cited as Project Independence.

[3] Science Magazine (November, 1974), at 427.

[4] Id. at 427.

have many inequitable results, and impose an undue burden on American citizens who are waging a battle against inflation during recessionary times. In addition, higher taxes on refined products may place an unacceptable burden on lower income families who proportionately spend more of their income on energy supplies.[5]

The President's proposal for accelerated O.C.S. development cannot begin to meet America's energy demands for another 8 to 12 years. Aside from the problem of lack of skilled manpower, drilling platforms and rigs, etc., necessary lead time would leave tracts now leased undeveloped for 4 to 5 years.

Stringent federal, state and local energy conservation legislation is necessary to make energy conservation a reality. If energy growth rates should be reduced to 2% a year, a harmonious balance between energy supply and energy demand could be attained.[6] A recent Ford Foundation Study[7] indicates that strong conservation measures would preclude the need to accelerate strip mining or offshore drilling for at least 10 years without affecting economic growth.[8]

Another issue to take into consideration is the need to conserve limited natural resources for future generations. If the historical growth rate continues, a time will come when

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[5] Ford Report, supra n.1, at 128.
[6] Id. at 326.
[7] Id. at 326.
[8] Id. at 330.

future generations will not have sufficient fossil fuels. Increased demand and fewer fossil fuels will result in higher fuel prices, although, with the development of alternative energy sources, fossil fuels may not be needed to supply our energy needs. Uncontrolled energy growth during our lifetime will jeopardize the long-term economic growth of future generations.

There are those who argue against a comprehensive energy conservation plan out of fear that total governmental control and centralization of authority would result.[9] A decision to examine the implications of uncontrolled energy growth need not imply governmental coercion or a shift toward more governmental decisions and fewer private ones.

America's continued energy supply is an essential factor in this nation's economic, military, and social well-being. On behalf of the people, the federal government controls half of the nation's most accessible energy supplies.[10] Decisions about how to lease these lands and at what pace are in the hands of the government. Without a uniform and purposeful energy policy (which includes a comprehensive conservation plan) the government would not fulfill its responsibilities to the American people.

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9 Stanford Research Institute, Meeting California's Energy Requirements: 1975-2000, Menlo Park, California, May, 1974 at 144 Herein cited as Stanford Study.

10 Ford Report, supra n.1. at 270 ... The national resource base is extensive; federal domain includes all public land, the O.C.S., and energy resources underlying some private land.

Oil companies have reaped tremendous profits from petroleum production. Unfortunately, oil companies are not accountable to the public but to their shareholders. Most industries function under economic pressures to maximize their short and long term profits. Under the present lease system, oil companies exercise substantial control over leased land developments, refinery production capacities and known natural resource reserves which go untapped. The lack of government control is the issue. Only the government can make decisions regarding trade-offs between environmental, social and supply questions.

By adopting strong incentives for energy conservation, the nation would curtail wasteful habits, ensure continued fossil fuels for future generations, and promote long-term national independence. We believe that the law requires consideration of the alternative of conservation. A number of conservation alternatives which must be considered could be implemented without loss of requisite services, life amenities, and without increasing the present life cycle cost of any specific energy development project.

2. Conservation Alternatives

(a) Transportation

(1) Motor Vehicles

Transportation consumes approximately one-quarter of America's total energy output.[11] Automobiles and trucks account

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[11] Id. at 57.

for approximately 75% of the transportation energy.[12] Yet, automobiles are one of the most inefficient means of transporting people. Trains, on the other hand, are the most efficient carrier of people. Then its use, however, continues to decline while airlines, the least efficient energy user, are the most rapidly growing form of mass transit.[13]

Increased vehicle fuel consumption can be attributed to numerous factors such as heavier automobiles, increased reliance on automatic transmissions and air conditioning. Some would blame environmental regulations as the major cause of poor mileage performance and added maintenance costs. According to a study conducted by the Environmental Protection Agency (hereinafter referred to as E.P.A.), however, such allegations are unsupported.

Data collected from more than 2,000 1973 automobiles indicate that fuel economy loss due to pollution control systems is less than 8% when compared to uncontrolled vehicles.[14] On the other hand, fuel economy loss due to air conditioning averages about 9% in normal weather conditions. Hot weather in urban traffic results in a 20% loss.[15] The most important reasons for the decrease

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[12] Id. at 57.

[13] Id. at 57.

[14] Remarks by Russell E. Train, then Chairman of the Council on Environmental Quality, Washington, D.C., June 13, 1973, at 3.

[15] Id. at 3.

in gas mileage are bigger and heavier automobiles. E.P.A. engineers found that new vehicles having the same model designation have become heavier. For instance, in 1958 a Chevrolet Impala weighed 4,000 pounds; however, a 1973 model weighs 5,500 pounds. Studies prove that, as a car's weight increases, gas efficiency decreases substantially.[16] A change of only 500 pounds can lower the average gas mileage by nearly 14%.[17] A 1,000 pound increase in weight results in a decrease of 30%.[18]

In 1973, 93.4% of all cars sold in the United States were equipped with automatic transmissions.[19] Yet, cars with automatic transmissions have been found to be bigger fuel consumers than cars with manual transmissions.[20] The British Automobile Association states that a 4-speed manual transmission saves 12 to 15 percent on gas consumption.[21] The British Automobile Manufacturers' Association bases its opinion on a variety of tests such as the much publicized Union Oil Company economy run. Among other cars, two American cars of the same make with

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[16] Id. at 3.

[17] Id. at 3.

[18] Id. at 3.

[19] Pope, Leroy, Automatic Transmissions Called Major Cause of Gas Shortage, The Los Angeles Daily Journal (1975).

[20] Id.

[21] Id.

comparable engines competed, one with automatic transmission and the other with a 4-speed manual gear box. The manual shift car won with 23.1 miles per gallon to the 20.1 miles per gallon for the automatic transmission, a 15% savings.[22] The Automobile Manufacturers' Association claims that the results were achieved with professional drivers and that similar savings would not be realized by normal-skilled drivers.[23] However, the British pointed to several extensive studies which involved European, American and Japanese cars. The tests were conducted under simulated average driver efficiency rather than professional driving skills. The results showed a 12 to 15 percent fuel saving for manual transmissions.[24]

There is no reasonable basis to blame environmental regulations for fuel economy loss; rather, poor vehicular design and engineering properties have yielded the real reduction in mileage performance. Nonetheless, this incorrect misconception of the effects of environmental regulations are prompting individuals to propose a ban on environmental controls. An example is President Ford's proposal for a 5-year delay on automobile pollution standards to achieve a "40% improvement in gas mileage". One problem with the President's proposal is that it implicitly blames pollution controls for lowering gas mileage. Secondly,

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22 Id.

23 Id.

24 Id.

at the cost of a small reduction in gas consumption, degradation of air quality will increase. Abeyance of pollution standards combined with increased reliance on coal (as natural gas supplies decrease) will result in continued deterioration of the environment. The trade-off between improved fuel economy and environmental degradation is unbalanced. An alternate proposal which can achieve the dual goals of more efficient fueled vehicles and clean air is urged here.

Through rather simple engineering innovations, it is technically and economically feasible to improve overall mileage from the average 12 miles per gallon to 20 miles per gallon by 1980 and to 25 miles per gallon by 1990, without shifting entirely or even predominantly to small cars.[25] Much can be done to improve fuel economy through design and engineering changes. For example, within a short time span, improved fuel consumption from 12 to 20 miles per hour per gallon can be reached by the following methods: (a) aerodynamic drag reduction through body redesign (which would result in a 5% fuel economy improvement); (b) rolling resistance reduction through use of radial tires (which would yield a 10% fuel economy improvement); (c) better load to engine match (which would result in a 10 to 15% fuel economy improvement); (d) substitution of 300 pounds of aluminum for 750 pounds of steel (which would result in an 18% fuel economy improvement);[26] (e) installation

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[25] Id. Ford Report, supra n.1, at 57.

[26] Id. at 59.

of manual transmissions and use of 4-speed transmissions (which would result in a 12 to 15 percent fuel economy improvement

Such improvements might result in a price increase of $450, but the fuel saving would more than compensate for the extra investment.[27] Many small and medium sized cars already average 20 miles per gallon or more. If the above suggestions were transferred into small car design, even greater savings in fuel economy could be realized.

Strong enforcement of the 55 miles per hour speed limit can reduce gas consumption by 2.8% for total automobile and small truck use and 1.6% for total national transportation fuel use. The forecast for automobile fuel use through 1990 projects an annual savings of about .31 quadrillion BTU in 1980 and about .33 quadrillion BTU in 1985.[28] Another benefit of reduced highway speeds is the sharp reduction in highway fatalities. The National Highway Traffic Safety Administration reports that total traffic fatalities for the first third of 1974 were reduced by almost 25% relative to the first third of 1973, an average of about 1000 lives saved per month.[29]

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[27] Id. at 59.

[28] Project Independence, supra n.2, at 106 of Appendix A.

[29] Id. at 106 of Appendix A.

On a long-term basis, development of more efficient engines can further enhance gas mileage while decreasing energy consumption. One promising model is a lightweight diesel engine,[30] which is widely used in Europe by taxicabs because of its high fuel economy at the low speeds characteristic of urban driving.

If this and similar transportation measures were adopted, energy savings of 16 quadrillion Btu could be achieved by the year 2000. In other words, if the historic growth rate were to continue, transportation energy use would be 43 quadrillion Btu. If these and other conservation measures were adopted, only 27 quadrillion Btu would be consumed---or a 38% reduction of fuel consumption.

(2) Mass Transit

Public transportation is two to four times more energy efficient than the automobile and offers the benefits of improved air quality, reduction of congestion, and savings in fuel consumption. However, since World War II, ridership on urban public transit has fallen sharply, from 19 billion trips in 1945 to 5 billion trips in 1973.[31]

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30 Dekeney, J.P., and Austin, T.C., Auto Emissions and Energy Consumption, United States Environmental Protection Agency, Ann Arbor, May, 1974.

31 Id. at 63.

The private automobile now dominates the urban passenger travel market. The decline in popularity of mass transit has led to the present poor quality and inadequacy of public transit services. There are several ways to stimulate increased transit ridership: improving services by adding new equipment, improving public information and advertising about such services, and developing new forms of transit.

In order to increase the use of public transit and discourage inefficient use of automobiles, the following suggestions were offered by Project Independence Blueprint and are incorporated herein: (a) increasing consumer costs for operating cars in urban areas by raising tolls on bridges and highways entering cities; (b) increasing urban parking fees; and (c) establishing annual fuel use license fees. If auto incentives were used in combination with public transit incentives, bus ridership could increase by 20%.

Substantial fuel savings could be realized if intra-city travelers switched to mass transit. Various forms of mass transit presently exist: subways, monorails, buses, and new systems such as the Bay Area Rapid Transit (BART) in San Francisco. New systems could incorporate such innovations as flywheel or electric storage systems which capture heat otherwise dissipated in braking operations.[32] Such systems would be a bonus for

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[32] Id. at 63.

underground transportation lines because the mechanism can retain heat loss and thus greatly reduce the air conditioning load in underground stations.

(3) Tax Incentives for Improved Ground Transportation

Our energy conservation proposal is geared toward reducing the historic energy growth rate by 38% by the year 2000. In order to encourage citizens to adopt new transportation habits and to encourage auto makers to produce more efficient cars, certain tax incentives should be implemented:

a. Federal subsidies should be offered to auto makers who produce cars that are lighter, have more efficient engine systems, and are better designed aerodynamically.

b. A tax should be levied on new and used cars which are unable to meet improved fuel economy standards of 20 miles per gallon.

The tax should be imposed no later than 1985 as it provides sufficient lead time for both new and used cars to reach the improved fuel standards. A sliding scale should be established so that, as a car's gas mileage worsens, the tax rate is higher.

New car buyers should be encouraged to invest in more efficient automobiles. Used car buyers should be urged to conside cars which are capable of getting 20 miles per gallon. Today, som

medium-sized and small automobiles are capable of meeting the new fuel standards. In addition, as auto makers slowly improve the engineering and design properties of new cars to meet the 1980 fuel standards, interim cars will get lighter, and more energy efficient. As today's new cars become tomorrow's used cars, a greater number of previously owned automobiles which can meet the 20 mile per gallon standard will be available for resale. The tax would be one means of encouraging used car buyers to bypass low performance cars in favor of more efficient vehicles.

More federal money must be allocated to funding mass transit. Though each state has different transit needs, more government funds must be directed to state a d local governments to permit renovation or construction of improved mass transit systems. In his State of the Union Message, President Ford failed to mention the need for emphasizing mass transit as an affirmative means of decreasing energy consumption.

Revitalized or new transit lines will relieve the energy-related economic crunch on middle and low income families who spend proportionately more of their income on energy consumption.[33] In addition, mass transit will relieve urban traffic congestion while reducing mobile source emissions.

(4) Air Transportation

In the past, air transportation has not been a major

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[33] Ford Report, supra n. 1, at 128.

energy consumer. Projected growth of energy use, however, is expected to be 13% to 14% per year. The spectacular growth may be attributed not so much to passenger transport but to freight air transport.[34] Translated into more concrete terms, energy use will increase from 1970 consumption of 1.2 quadrillion Btu to 11.6 quadrillion Btu by the year 2000.[35]

A number of practical measures should be implemented in order to decrease fuel consumption. First, the Civil Aeronautics Board should increase the load factors (seating capacity filled). Current scheduling regulations result in an average load factor of 54% of capacity. The recommended load factor is 67% capacity. This improvement would result in a 28% direct fuel savings for domestic flights and an 8% savings for international flights.

Second, a reduction in flight speed would also result in energy savings. In the past, airplanes have traveled faster than the speed at which fuel consumption is most efficient. Reduction of speed to this level would result in a 4.5% fuel savings. "The net result would lengthen flight times only 6%--only 20 minutes for a transcontinental flight."[36]

Third, the C.A.B. should consider scheduling flight frequencies. Though air transportation is efficient in terms of time savings, it is extremely wasteful from an energy viewpoint: passenger transport is twice as efficient by rail and car; freight transport is more than ninety (90) times more efficient by rail and twenty (20) times more efficient by truck.[37] Thus, it is proposed that short haul air freight (less than 400 miles) should be shifted to truck and rail facilities.

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34 Id. at 49.
35 Id.
36 Id. at 57.
37 Id. at 63.

(b) Commercial and Residential Building Design

(1) The Problem

"In the residential sector, the greatest potential for energy conservation lies in space conditioning which, at present, accounts for more than 60% of residential energy use."[38] In the commercial building sector, approximately 90 out of every 100 buildings operate at less than 90% of their potential energy efficiency due to poor maintenance.[39] Such single-purpose buildings with short occupancy times and lack of diversity for 24 hour use consume more energy per hour than multiple use buildings.[40] The primary energy uses in the building sector can be summarized as follows:

a. 57% for space heating and air conditioning;

b. 33% for operating equipment, including hot water heating, home appliances, and office equipment; and

c. 10% for lighting.[41]

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[38] Project Independence, supra n. 2, at 123 of Appendix A.

[39] Id. at 223.

[40] Ford Report, supra n. 1, at 51.

[41] Id. at 55.

The potential savings in energy consumption are substantial if an optimum combination of design improvement, including construction and maintenance policies, are implemented.[42] If the historic growth rate for residential energy use were to continue, it is projected that homeowners would consume 32 quadrillion Btus by the year 2000. If conservation measures to improve space heating, air conditioning, water heating, etc., were implemented, projected use would be 20 quadrillion Btu or a savings of approximately 38%.[43]

Many construction and rental market practices do not encourage the introduction of more efficient, economical and attractive building designs for heating, ventilation and air conditioning. Most houses, apartments and office buildings are built by speculative builders who are under intensive competitive pressures to sell or lease their buildings at the lowest apparent cost to the interested parties. Thus, energy savings investments are discouraged because people with authority in building designs are usually not the same people who operate them and pay the utility bills.

(2) Building Code Modificiations

The regional specialization and decentralized nature of the industry makes specific federal proposals inappropriate. However, the federal government can play a

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[42] Id. at 223.

[43] Id. at 51

key role in encouraging better construction and insulation designs by establishing the following policies:

First, revise the nation's building codes and periodically update them to make energy conservation a priority consistent with life cycle economics based on energy prices.[44]

Second, make the federal building code a model to promote energy daving construction practices.[45] Agencies such as the Federal Housing Authority, Veteran's Administration and Small Business Administration, can revise their standards for issuing loans by requiring a life cycle cost for building designs.

Third, set an example for the nation by only purchasing buildings which are energy sufficient.

Fourth, establish lending programs to provide lower income home owners with subsidized, guaranteed loans which would allow them to improve the energy efficiency of their homes.[46]

State and local governments should rewrite local building codes. Because of regional climatic variations, building requirements will have to be varied. Regional agencies can undertake studies which will provide valuable information for reevaluating present building codes. An example of

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[44] Ford Report at 55.

[45] Id. at 55

[46] Id. at 56

possible revisions in state and local building codes may be found in the Southern California Coastal Commission Findings regarding building and urban designs. A summary of their findings are set forth below:

a. Reducing the area of glass windows generally saves initial and operating costs (and energy). The loss in natural light will require increased artificial illumination but this is more than offset by the gain in energy saved by the reduction in heating and cooling loads. For example, solar heat transmission is greatest through glass windows. 60 square feet of glass on a western exposure of a building will require a ton of refrigeration for cooling and consume a kilowatt per hour.[47]

b. A reduction of the surface of buildings not used for alternative heating and cooling energy systems may result in a reduction of the energy required for space heating.[48]

c. Inaccurate engineering calculations, excess safety factors, failure to account for people and appliance loads result in oversized equipment and inefficient operations.

d. The stack effect in buildings, (that is, the tendency of high buildings to internally generate a powerful rising draft of air within the vertical service stacks) introduces unwanted outside air infiltration which building designs are generally inadequate to prevent.[49]

e. The present lack of energy storage systems to store heat and cold results in a loss of

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[47] Energy Element, supra n. 36, at 58.

[48] Id. at 58.

[49] Id. at 58.

energy which otherwise could be stored for later use. This results in an increase in peak electrical need.[50]

f. Conventional chimneys, fireplaces, combustion devices, kitchen, laboratory, and laundry exhaust hoods are energy wasters. Heat exchangers can be used to recapture the energy.[51]

g. More stringent insulation in walls, ceilings and floors and double glass windows, possibly with special coating, can show significant reduction of energy usage. Savings of up to 50% for the energy required for heating and 20% required for the energy required for cooling in new residential construction and 10% of both the heating and cooling energy in new commercial construction can be achieved.[52]

These findings are an example of how relevant energy efficiency studies can be conducted by state and local government which ultimately lead to a reevaluation of existing building codes. Energy efficient construction codes will result in higher investment costs. However, studies show that the life cycle maintenance costs far outweigh the investment costs. For example, increased insulation costs for new homes will be approximately $700 extra.. This additional cost includes insulation of a 1200 square foot home with storm windows, heavier insulation in the walls, ceiling and floor. "If the

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[50] Id. at 59.

[51] Id. at 59.

[52] Stanford Study, supra n.9, at 144.

homebuyer gets a 10 year loan at 10% to finance this investment, his annual payment on the loan would be about $110. Comparing this house with a typical insulated house in New York, this investment would save about 400 to 500 gallons of fuel oil per year, a dollar saving of $100 to $150 and a net saving of $10 to $40 a year. The insulation would produce further savings by reducing the electrical requirement for air conditioning."[53]

In addition, state and local governments could encourage development of new homes in clustered dwellings with built-in support activities. Clustering of dwellings in multiple units conserves energy for heating and cooling, since the ratio of surface to heated volume tends to decrease with increased building size. Planned unit development and major activity center developments provide opportunities to combine many sub-energy systems so that the sum of energy consumed for all processes working together is less than the total of individual systems operating separately. A rich diversity of transaction opportunities would reduce the need for trips out of residential areas if an activity center were planned in a convenient centralized locality.[54]

These proposals do not centralize more government decisionmaking. Rather, these measures give new direction to an industry by promoting sounder construction practices while

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[53] Ford Report, supra n. 1, at 48.

[54] Energy Element, supra n. 36, at 230.

conserving valuable and limited resources. As in the past, decisions in regard to specific building codes and development plans still remain with local governments. This particular practice allows for local input into a vital decisionmaking process.

(3) Tax Incentives for Improved Building Design

In order to spur adoption of energy conservation programs, certain tax policies should be revised. For example, existing price methods in electricity consumption promote energy growth through discounts for greater use at a time when greater conservation is needed. Electricity rates should no longer include discounts for large users. Rather, such rates should reflect the additional cost of generating extra power during peak hours.[55]

Another proposal is to encourage homeowners to install better insulation properties. Under this plan, any owner of a residential building who installs thermal insulation, storm windows, and day/night thermostats would be able to claim a tax credit on his income tax equal to 25% of the material and/or labor costs.[56] The credit would be

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[55] Ford Report, supra n. 1, at 258.

[56] Project Independence, supra n. 2, at 133 of Appendix A.

limited for a specified time period in order to encourage immediate response. Even without price or tax incentives, the rate of return on capital investment is about 14% (in real terms).[57] Thus, an increased rate of return coupled with a tax credit could spur residential owners to install such energy efficient properties. Projected annual energy savings as a result of retrofitting residences is 1.14 quadrillion Btu per year by 1980.[58]

A similar tax credit should be considered for commercial building owners. A 15% tax credit would be allowed on materials and/or labor costs which result in energy-saving modifications to existing buildings. The tax credit would be available for a specified time period. Anticipated energy savings would be .15 quadrillian Btu by 1980 and .18 quadrillion Btu by 1985.[59]

Tax credit programs such as those suggested here benefit low and middle income families as much as high income families. Tax credits have the effect of lowering the initial installation costs to building owners. Lower installation costs have two impacts on the owner's investment decision: (1) with the tax credit, the owner can have less cash set

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[57] Id. at 134 of Appendix A.

[58] Id. at 133 of Appendix A.

[59] Id. at 141 of Appendix A.

aside for the down payment, and (2) because the initial cost is less while the stream of savings remains the same, the rate of return on the project increases.[60] These proposals are tax measures which can be promulgated within a short time period without undue federal costs and at a tremendous energy savings.

(c) Industry

Industry's energy consumption accounted for 33% of the U.S. total energy consumption in 1972 or approximately 23.7 quadrillion Btüs per year.[61] The largest energy users include cement, steel, petroleum refineries, paper, aluminum, chemicals, glass, copper, and food industries.

A number of different reasons prevent more efficient energy use, some which can be remedied on a short term basis, while others require long term development.

1. Industry normally does not conserve energy when energy costs account for a small portion of total costs.

2. Many industry administrators lack awareness of energy conservation potential in processes and plants.

3. Some industries suffer from the unavailability of energy efficient processes, techniques and equipment.

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[60] Id. at 134 of Appendix A.

[61] Id. at 154 of Appendix A.

4. Some industries are unable to invest in new plants and/or equipment because of constraints such as capital availability at reasonable costs.[62]

Yet energy efficient technology exists which can be implemented by a majority of large energy users on a gradual basis over the next 10 years. Possible means of saving energy for each industry will be discussed, after which a proposal for implementing such changes will be presented.

(1) Petroleum refineries

A typical petroleum refinery is defined as a combination of standarized unit processes. A series of processes are necessary to convert crude oil into refined products. The energy consumed in this conversion is strongly dependent on the product mix required and on the specifications of the products. Energy efficiency can be improved through:

1. Implementation of better maintenence of existing equipment, improved systems control and training of individuals to recognize wasteful practices.

2. Recovery of process heat losses and recovery of power waste flue gases, steam and processed streams.

3. Modifying product specifications to minimize energy consumption patterns.

4. Optimizing apacity utilization to minimize energy consumption patterns.

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62 Id. at 156 of Appendix A.

Projected energy reduction can be reduced by 20% or approximately .7 quadrillion Btu by 1985. Though some of the suggestions will require capital expenditures, energy savings may be sufficient to offset investments.

(2) Plastics

Enormous amounts of energy are used in the manufacturing of selected plastics (low-density polyethylene, high-density polyethylene, and polyvinyl chloride resins). Energy costs can be as much as 30% of the selling price of the products. An increase in the cost of energy will have a significant effect on the cost of producing plastics.[63]

A reduction in energy consumption can be achieved by: (1) the use of raw materials (resins) which require less energy, and (2) shift away from high cost oil and gas to coal. The energy reduction potential in this industry group is estimated at 25% or approximately .5 quadrillion Btu by 1985.[64]

(3) Cement

There are two basic processes for manufacturing portland cement, wet and dry. In the wet process, grinding

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63 The Federal Energy Agency accounced KNBC Evening News, January 23, 1975.

64 Project Independence, supra n. 2, at 159 of Appendix A.

and blending of raw materials is carried out without using a slurry of the materials in water. In the dry process, the grinding and blending is formed using materials in their natural (dry state). The energy consumed in the evaporating water in the cement kiln stage is a major user of energy. In the wet process 8.04 million Btu are used to manufacture each ton of cement. In the dry process, on the other hand, only 7.25 million Btu per ton are used to manufacture cement. Conversion of wet plants to dry plants is a potential source of energy savings.

Most of the energy consumed by the cement industry is used in the kiln proces. Electricity is the main fuel used in the process of grinding raw materials and operating the kiln. Improved grinding processes, including air classifiers which use hot fuel exit gases, can reduce electricity consumption.

Heat recovery systems are another way to reduce energy consumption. If most cement plants in the U.S. had efficient heat recovery attached to their kilns, they could save as much as 40% of the fuel used at the end of the kiln. Another means of reducing heat consumption is the use of preheated kilns. Elaborate raw material preheater systems have been used in European plants. Such modern systems are able to cut fuel consumption by as much as 49% as compared to the older preheated kilns. Another means of increasing heat transfer is to raise the speed of rotation of the kiln.

Also, because about 16% of the heat loss occurring in the kiln is through the walls, improved insulation techniques in materials could produce substantial fuel savings.

These techniques are presently available and in use in newer cement plants throughout the world. Though installation of such improvements would require a capital investment, tax deductions and a reduction in energy consumption may be sufficient to offset the cost. Potential energy reduction is estimated to be 35% or approximately .3 quadrillion Btu per year by 1985.[65]

(4) Food Industry

Over the last few years, the increase in energy prices has affected the consumer indirectly through higher food cost. Some processers have experiended a doubling of fuel prices in 1973.[66] In the face of future fuel price increases, the conservation of energy is integrally related to minimizing higher food costs. Improved management of energy consumption has been receiving increased attention. New concepts are being developed and demonstrated such as:

1. Preheating of incoming water and use of heat from waste water;
2. Use of heat pumps to generate hot water for processes;

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[65] Id. at 160-161 of Appendix A.

[66] Id. at 159 of Appendix A.

3. Use of energy from the incinerator to supplement boiler fuels.[67] Such methods are capable of reducing energy use by 20% or .5 quadrillion btus by 1985.[68]

Agriculture has also examined some viable conservation measures which lower operating costs to farmer, and ultimately, the consumer:

a. A shift from gasoline powered tractors to diesel-powered engines which are more efficient and have higher btu content than other fuels. Thus, the same amount of work can be done with less than 27% of gasoline fuel. The switch to diesel fuel tractors is expected to increase to 57% by 1980 and 75% by 1985. Diesel-powered combines are also gaining popularity and could amount to 70-80% of all usable combines by 1985.

b. Reduction in plowing practices.

c. Using equipment which is capable of multiple functions such as planting, applying pesticides and fertilizers in one process.

d. Place greater emphasis on biological pest control methods, thereby reducing the need for petroleum based pesticides and herbicides.

e. Use of natural fertilizers as a substitute for fertilizers which are petroleum and natural gas intensive.

f. Use of wind mills for pumping water to animal water troughs as an alternative to electrictical pumping systems.

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67 The Federal Energy Agency Announced on January 23, 1975 that an increase in petroleum products could cost the average American consumer $265 to $350. Cost increase is attributed to higher plastic products. KNBC Evening news, January 23, 1975.

68 <u>Project Independence</u>, <u>supra</u> n. 2, at 159 of Appendix A.

If such methods are implemented, the conservation potential in group amounts to 20% or approximately .5 quadrillion BTU in 1985.[69]

(5) Paper, Aluminum, Copper, and Glass

These four industries have already implemented recovery programs which recycle used material for making new products. It has been demonstrated that recycled production is fuel efficient. An accelerated program could result in substantial savings while preserving limited valuable resources for future.

When two productions systems are compared, one using virgin materials and the other using recycled materials, the system using recycled materials consumes less energy when all stages of materials acquisition, processing and transportation are included. For the following materials, energy savings per ton of material recycled are:

a. Aluminum - 2 million Btu per ton

b. Ferrous - 12 million Btu per ton

c. Glass - 1.3 million Btu per ton[70]

Recycling discarded products has been shown to be technically and economically feasible.

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69 Id. at 162 of Appendix A.

70 Id. at 171 of Appendix A.

Almost 14 million tons of these materials could have been recovered and substituted for virgin material counterparts, and energy savings would have totaled about .172 quadrillion Btu.

Recycling of paper at maximum practical recovery rates would reduce the energy potential of solid waste burning by about 10%. There would be further reductions in air, water, and land pollution associated with producing paper from virgin pulp. Using recycled fiber in paper and production systems appears to require less energy than using virgin pulp wood; however, conclusive data are not yet available. [71]

(6) Steel

The steel industry is one example of how additional research and development is necessary before energy savings can be realized. The availability of new energy efficient equipment is already a problem. With proper planning by suppliers, it could be resolved over the long term. Newly developed technology will not be available for implementation until the 1980's, whether developed by private industry, government or both. With awareness of emerging technology and proper planning between now and 1980, action could be taken to fill the supply pipeline with needed materials.[72] The research and development program would concentrate on demonstrating promising new

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71 Id. at 171 of Appendix A

72 Id. at 171 of Appendix A

73 Id. at 170 of Appendix A

technology as rapidly as possible. New technology must also be oriented to process efficiences which would include environmental pollution abatement.

The federal government can and should influence the level and pace of energy conservation efforts by U.S. industry. The government should focus on technology development which is both economically and energy efficient. Because a large portion of the total energy demand is consumed by industry, it is essential that adequate plans for industrial energy conservation be prepared. Therefore, we propose the following:

a. The largest firms in the ten major energy consuming industries be required to submit an energy conservation plan;

b. Increase federal and private industry research, development and demonstration programs oriented toward energy conservation technology in industrial processes; and

c. Conduct major public information dissemination programs.

(d) Natural Gas[73]

Continuously operated gas pilot lights in the 30 million gas-heated homes in the United States are estimated to consume more than 223 billion cubic feet of gas annually. In addition, pilots account for one-third of the total gas consumption of a typical gas range and may even account for as much as one-half of the total use where pilot flames are set too high. Safe electric or other types of ignition devices are available as a substitute for pilots in most residential-type appliances, and may be both built into new appliances and fitted into existing appliances. Replacing gas pilots in existing appliances may cost $80 to $100 and probably cannot be justified as a long range cost-benefit to the consumer. Electric ignition devices, however, may add only $3 to $30 to the cost of a new appliance and the reduced operating cost of the appliance is likely to more than offset the initial capital cost to the consumer over the life of the appliance.

California Senate Bill 1521 was passed in May 1974 and prohibits the sale or installation of all new residential-type gas appliances, except water heaters, equipped with a pilot light 24 months after an effective "intermittent ignition device" has been demonstrated or certified by the State Energy Commission, or January, 1977, whichever is later. Additions to existing structures as well as the residential applications are required by S.B.5121 unless

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[73] California Coastal Zone Commission, Revised Draft of Sixth Plan <u>Element, Energy</u> (1975), at 66-68, 96-99.

equipment manufacturers can conclusively demonstrate that the gas pilot: (1) has a lower cost than alternative ignition systems over the life cycle of the piece of equipment; (2) is more energy efficient than alternative devices for a particular piece of equipment; or (3) that public health or safety necessitates the use of gas pilots.

Routine maintenance of most gas appliances may also substantially reduce energy consumption. Dirt build-up or improper adjustment can reduce the efficiency of most gas appliances by as much as 50 percent.

The California Coastal Zone Conservation Commission further recommends that open gas flames not be allowed for advertising, promotional or decorative purposes in proposed new industrial, commercial or residential construction or additions. The Commission's recommendation is directed to both exterior and interior installations.

(e) Lighting[74]

Lighting accounts for 20 to 25 percent of U.S. electricity consumption. In office buildings, lighting represents an even larger fraction, averaging 40 percent and in some cases up to 60 percent of the electricity use. Promotional uses, which include decorative lighting, advertising and display lights and exterior wall lighting are large users of electricity.

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[74] Id. at 68-71, 89-93.

Nationwide there has been a substantial increase in the average lighting intensity in commercial buildings. From 1940, when the average was 35 foot-candles, average lighting levels increased to 85 foot-candles in 1958 and to 124 foot-candles at present. However, many experiements indicate that lighting intensities between 10 and 50 foot-candles are sufficient for most usual activity and physiological needs rather than the 60 to 150 foot-candles levels currently being provided. Furthermore, lighting levels can be significantly reduced in areas such as corridors, lobbies, passageways, and storage areas. At the same time, within "work areas", selectively higher lighting levels may be used for "task zones" to both reduce the total lighting need and to increase the effectiveness of people working within the area. The Coastal Zone Commission has found that lighting levels for tasks up to 100 foot-candles can be achieved in most buildings designed for a maximum average requirement of 2.3 watts per square foot and recommends that lighting not exceed 2.3 watts (2.5 volt-amperes) per square foot except where higher levels are shown to be necessary for public health and safety. Where specific tasks require an extremely high degree of visual activity, exceptions may be made on a case-by-case basis.

Lighting needs may be further reduced by optimizing the use of natural light. In major office buildings and schools, a reduction of about 25 percent of the energy used for lighting may be attained if lighting fixtures near windows could be manually switched off or automatically controlled by a photo cell. The Coastal Zone Commission thus recommends that light

switches be provided so that portions of the building not in use or receiving sufficient natural light may be switched off selectively.

Selection of the type of light source is significantly related to energy consumption. Incandescent light bulbs are inefficient energy converters, using only 10 to 14 percent of the energy consumed for lighting and converting the rest to heat. Fluorescent lamps, on the other hand, are more than three times as efficient. The Coastal Zone Commission therefore recommends that only efficient lamps and luminaires as defined in the criteria of Section 9.3 and 9.4 of the Design and Evaluation Criteria for Energy Conservation in New Buildings (Proposed Standard 90-F) of the American Society of Heating, Ventilating, Refrigeration and Air Conditioning Engineers (ASHRAE) be allowed. Excessive and inefficient lighting indirectly causes an additional energy burden by increasing the heat load and thus increasing the need for cooling. Typically, every two watts of lighting requires one watt of cooling by air conditioning. The air conditioning burden may be reduced by use of "heat-of-light" systems which reduce the amount of heat generated due to lighting.

Selection of lamp type is also important for street lighting and other outdoor illumination. The standard mercury vapor lamps consume 2.3 to 2.9 times the energy for an equivalent amount of light than the more recently developed high pressure lamps (HPS). Although HPS lamps are both more costly and have a shorter life than mercury vapor lamps, experts agree that over the life cycle of the system HPS systems are in fact less costly than mercury vapor systems. The South Coast Regional Commission

indicates that substitution of HPS lamps for mercury vapor lamps could have saved 205 million kwh out of a total 307.6 million kwh used for street lighting in Los Angeles County in 1973. The Coastal Zone Conservation Commission thus recommends that new street and highway lighting use HPS lamps unless there are environmental, aesthetic, or public safety reasons for using another type to be equally or more efficient. It may be further possible to reduce the intensity of street lighting without adversely affecting public safety.

The Coastal Zone Commission recommends that electrical consumption for promotional signs and lighting can be reduced by regulating the size, type of lighting, and extent of such uses. While the energy use from electric signs accounts for less than 0.2 per cent of the total energy use in California, the South Coast Regional Commission estimates that prohibiting of all outdoor ornamental and advertising flood lighting and limiting businesses to one outdoor illuminated sign for advertising purposes would reduce energy consumption by about 1-1/2 per cent units.

The Coast Zone Commission policy then is that no new advertising or ornamental signs in the coastal zone shall be electrically lighted except that businesses are allowed an on-site lighted sign for identification purposes which can be illuminated during darkness only during business hours; building and facade lighting other than signs is limited to the greater of 1000 watts or 2 per cent of the lighted interior load of the building.

(f) Heating, Cooling and Ventilating Systems

Eighteen per cent of the total national energy consumption is for heating buildings. Only 1 out of every 10 buildings, however, operates at 90 per cent or more of potential energy efficiency. Up to 50 per cent of the heating and cooling demand in buildings is a result of infiltration of outside air, due to inadequate insulation, caulking, and weather-stripping of almost all existing buildings. If these were improved in all existing buildings, 7.2 per cent of total nation wide energy consumption could be saved. In new construction, more stringent insulation standards (applicable to walls, ceiling, and floors) and double glass windows, possibly with special coating, could effect significant reductions of energy usage. Savings of up to 50 per cent of the energy required for heating and 20 per cent of the energy required for cooling in new residential construction and 10 per cent of both heating and cooling energy in new commercial construction could be achieved.

Use of electric resistance space heating results in consumption of at least twice as much energy to heat a given space as direct use of a primary fuel (e.g., gas or oil). The conversion efficiency for a fossil or nuclear fuel thermal electric power plant is only about 35 per cent; inefficiencies in transmission and delivery systems still further reduce the overall conversion efficiency for electric space heating. If gas is used directly for space heating, overall efficiency will range from 50 to 80 per cent, even considering inefficiencies due to improper furnace adjustment and start-up and shut-down operations.

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[75] Id. at 72-7, 93-6.

The Coastal Zone Conservation Commission therefore recommends that for new or substantially remodeled residential, commercial, institutional or industrial developments no electric resistance heating (water or space) shall be allowed unless: (1) an effective solar delivery system and/or natural gas service are not available or adequate for meeting energy requirements; (2) electrical heating is needed for medical, health, or public safety reasons; (3) some other unusually high requirement for clean heat exists; or (4) a back-up system for solar heating and cooling systems is required.

Air conditioning's share of annual total national energy consumption has grown from an infinitesimal amount 20 years ago, to 1.6 per cent in 1960, to 2.5 per cent in 1968, to possibly as much as 4 per cent now. Because most of this energy is consumed during just a few months of the year, the strain of air conditioning loads on electric generating resources can be severe. One of every two homes in the country has at least one room air conditioner. One-half of new houses being built today are centrally air conditioned, compared to 1/20th a decade ago.

Among various types and makes of conventional room air conditioning units, energy efficiency in actual "cooling capabilit can vary by as much as 80 per cent. Large central heating and air conditioning systems generally use 10 to 15 per cent less energy on the average than smaller decentralized systems. If central systems are to operate with the same flexibility as individual systems, however, proper controls must be installed.

The use of trees, shutters, sun screens, awnings, and

roof overhangs to shade windows from direct sunlight can substantially reduce heat build-up in buildings, and thus air conditioning requirements. Special glazing (metal-coated and/or double wall glass) can cut both cooling and heating requirements by about half. It is much more efficient to screen glass on the exterior, rather than with blinds, drapes, etc., on the interior of a building.

Heat transmission rates are also affected by the proportion of exterior walls, the amount of surface area in windows (heat loss and gain from windows causes much greater energy use than the potential saving in natural lighting), and the color, orientation, shape, and angle or exposure of building surfaces.

Operable windows in lieu of fixed glass will allow natural ventilation to enter the building, eliminating some of the need for air conditioning and mechanical ventilation during much of the year. Such windows must be well fitted and weather-stripped to reduce infiltration of outside air.

The Coastal Zone Commission recommends that for new or substantially remodelled developments air conditioning needs should be reduced by: (1) incorporating either mature planting, exterior architectural shading projections, or reflecting and/or insulating glass or exterior solar screens to shade or protect windows receiving direct sunlight in warm climates; (2) incorporating operable sash and vents in all exterior rooms for which ventilation is required by the local building code, and making such sash and vents weather-right by use of weather-stripping; and (3) having variable thermostats for areas with different air condition-

ing requirements. The Commission further recommends an air conditioning design using the best practical available technology with low-level or no electricity consumption shall be required and that new conventional (compressive refrigeration air conditioning shall be permitted only if an applicant can demonstrate that the life cycle costs of the conventional system are substantially less than the lowest cost alternative system available.

Heating and cooling systems are usually based on outdoor conditions not exceeded more than 2-2 1/2 per cent of the time. Except for facilities for the elderly, for industrial process, or for health care, such systems could be designed for the 5 per cent condition with only a slight increase in discomfort during a few hours per year. Excessive safety margins and failure to account for people and appliance heat-loads also result in oversized space conditioning equipment and inefficient operation.

Heating and cooling of vast amounts of outdoor air that circulate through buildings can also consume energy wastefully. By reusing already circulated air, the amount of outdoor air required for ventilation can be substantially reduced, from 5-15 cfm (cubic feet per minute) per person to 3-4 cfm per person in most buildings. Air quality can be maintained by using odor-absorbing devices and better filtration. Initial costs are no greater, since savings in fans, heating and cooling equipment, and ductwork more than offset the added costs for better filters and odor absorption equipment, and there are significant savings in energy and operating costs. Heat exchangers which allow the use of already air conditioned exhaust air from a building to preheat or precool

system intake air, are a means for reducing heating and cooling requirements in large buildings.

The present lack of capability of buildings to store heat and cold results in a loss of energy which otherwise could be used later to offset peak electrical demand loads. Conventional chimneys, fireplaces, combustion devices, kitchen, laboratory, and laundry exhaust hoods are all energy wasters. Heat exchangers can be used to recapture energy otherwise given off as waste heat.

Further energy conservation may be attained through the use of alternative heating and cooling systems. Among the systems which may potentially reduce energy consumption are:

Solar or Solar-Assisted Heating and Cooling.
(refer to Section II D, Energy Alternatives, infra.)

Heat Pumps. A heat pump is, in effect, a refrigeration machine that can work in a reverse cycle; thus it can either heat or cool a given space. Large electric heat pumps are comparable in efficiency to properly maintained gas furnaces; they can operate at two to three times the efficiency for cooling than most systems, especially compared to compressive refrigeration. A heat pump system can also be operated by solar power, thus further reducing electricity demands.

Nocturnal Evaporative Cooling. Roof-pond nocturnal cooling systems are technically feasible and practical for residential and low-load buildings in desert or valley climates such as in southern California, and are as effective as solar-powered absorption air conditioning. The evaporation in one hour of

1-1 1/2 gallons of water is the equivalent of one ton of refrigeration capacity; the operating cost would be only a fraction of the cost of electrical refrigeration. This is the simplest system that can accomplish both heating and cooling.

Rock-Bed Regenerators (RBR). Rock-bed regenerator (RBR) cooling systems use evaporation of water in the discharged air to chill rocks in a switched-bed rock-filled recuperator, which then cools inflow air. RBR's have been used successfully in Australia. The power consumption per square foot is only 1.0 watt compared to 8.8 watts (3-4 watts in California's coastal climate) for mechanical refrigeration.

(g) Research and Development

In view of the relative neglect of energy conservation in federal energy planning, it is not surprising that energy research and development (R & D) is out of step with society's needs. Only one energy supply, atomic power, has been substantially funded. The paucity of funds leaves many energy sources unexplored. This was evident as President Ford failed to allocate funds for research and development in his 1975 State of the Union message.

> This misdirection has taken place because of the absence of a coherent national energy policy. . . . Energy research and development efforts are dictated by narrow economic interests in the private sector, by established vested interest in government (of which the Atomic Energy Commission has been an outstanding example), or by a confluence of these narrow corporate and governmental interests.[76]

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[76] Ford Report, supra, n.1, at 306.

In 1973, the federal government allocated $643,000,000 for energy supply, research and development.[77] 74% ($480,000,000) was spent on nuclear energy. In comparison, the total expenditure on solar, geothermal, wind, and organic waste energy supplies was less than 10 million dollars. Research and development for energy conservation was funded at 20 million dollars while expenditures for systems research on health and ecological effects (about 20 million dollars) declined between 1972 and 1974.[78]

Though expenditures alone do not signify progress, they do indicate priorities. Little research and development funds have been dedicated to energy conservation or to the development of new sources of energy. Alternate forms of energy such as solar house heating[79] or production of methane gas from organic waste[80] have been explored and partially developed by private sectors; however, without additional government and private industry development, such promising technologies will not be able to mature to viable new sources of energy.

Five research and development goals should be included within the framework of a national energy conservation program:

1. Assuring energy supplies at reasonable prices;
2. Using energy efficiently;

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77 U.S. Department of the Interior, Office of Research and Development, "Energy Research Program of the United States Department of the Interior," (March, 1974.)

78 Ford Report, supra, n.1, at 306.

79 NSS/NASA Solar Energy Panel, An Assessment of Solar Energy of Solar Energy as a National Reserve, Univ. of Maryland (1972).

80 Fry, John L., Methane Digestors for Fuel Gas & Fertilizer, New Alchemy Institute, News Letter number 3, Woods Hole, Mass., (1973).

3. Compatability of energy systems with a clean and safe environment;

4. Energy dependence; and

5. Diversity in energy supply technologies.[81]

Two goals, energy supply, research and development and energy conservation, must receive equal attention as both are vital to lowering energy demand while assuring continued supply.

Environmental protection should be an integral part of an energy production and use policy. In the past, environmental concern has been more of an afterthought. As a result, expensive and sometimes inefficient control technology has been installed without much success. Past mistakes compelled the federal government and private sectors to include an ongoing environmental evaluation of potential new sources of energy. Hence, new energy source should come to the marketplace environmentally safe. In the short term, this is the price the nation must pay for previous neglect; in the long term, it is a means of balancing continued growth and preservation of an environment for future generations.

Research and development should be accelerated in order to promote energy independence. Alternative domestic oil supplies such as coal liquefication and shale oil can become economically and commercially plentiful by 1985.[82]

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[81] Ford Report, supra, n.1, at 308.

[82] Adelman, M.A., "Energy Sufficiency; An Economic Evaluation, Technology Review, 76:6, May 1974, pp. 44-47 and 56-58. See also U.S. Dept. of Interior, Final Environmental Statement for the Prototype Oil Shell Leasing Program, Wash. D.C., U.S. Government. Printing Office (1973).

Finally, diversity in energy sources is an essential component of greater flexibility. America must have greater energy options than at present. Unfortunately, both government and industry research have aimed primarily at technologies (such as coal gasification or nuclear power) which have significant economic promise. Energy sources such as wind power, solar energy, and solid and organic waste (which are not economically sensitive to large industry profits) have yet to receive significant research and development funding.

The Ford Foundation Study suggests seven major energy conservation projects which should be thoroughly researched and developed[83] as one means of reducing the historic energy growth rate.

(1) Heat Transfer Technology

Basic research should be done on heat exchange materials such as heat pipes, heat transfer properties of various heat exchanger configurations, and heat transfer fluids. Developments in this area would improve the efficiency of electricity generation and would also supply new technologies such as solar sea thermal power.[84]

(2) Low Temperature Heat Applications

Today, power plants, homes and office buildings generate enormous quantities of low temperature heat. Such energy

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[83] Ford Report, supra, n.1, at 318.

[84] Id. at 318.

is expensive and applications are limited. Research and development can help make low grade energy use cheaper. Development of new insulating materials and the cheap transport of low grade energy are also desirable for applications that do not intrinsically require high temperature heat.[85]

(3) Energy Savings and Space Conditioning

Research on heat transfer technology as applied to heating and cooling homes could yield substantial energy savings. Homes and office buildings possibly can be heated and cooled with just a fraction (on the order of 10%) of the fuel that is now used.[8

(4) Industrial Steam Production Technology

The application of solar flatplate collectives and low temperature energy storage to industry steam production could result in significant fuel savings. These collectors, if commercially developed, could also be usable in residential and commercial sectors.[87]

(5) Integrated Power Generation

New technology should be developed for integrating decentralized electricity generation with electricity distribution systems.[88]

(6) Improvements in Efficiency of Power Generation

Power generation efficiency can be improved through the use of fuel cells, topping cycles, bottoming cycles, and improv ing the load factor of generating plants. Such items are important to reduce the energy requirements for producing electricity and

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85 Id. at 318.
86 Id. at 318.
87 Id. at 318.
88 Id. at 318

for building power plants.[89]

(7) New Manufacturing Processes

Private industries should be encouraged to research and develop new manufacturing processes that will save substantial quantities of energy. Such development requires a cooperative effort by both industry and government.[90]

(h) Public Education

The government can implement incentives to promote fuel economy but public education and information are necessary functions which can raise the general level of consciousness. In the past, energy costs were low and represented a small fraction of a product's purchase and maintenance cost. With higher fuel costs, energy savings should be an integral consideration in the purchase of a product.

In order to make economically sound decisions, adequate and reliable information is necessary. For example, major appliances should be labeled indicating its energy requirements and operating costs. This would enable the consumer to evaluate the trade-offs between higher initial investment versus lower operating costs.[91]

Another example is to require builders or lessees to provide accurate information concerning utility cost to improve rental or purchase decisions. Though disclosure of such data may

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[89] Id. at 319.

[90] Id. at 319

[91] Id. at 53.

not be of sufficient importance for the construction industry to design and build structures with improved insulation, etc., it is one more step toward furthering that objective.[92]

Widespread educational programs should be offered by local agencies and utility companies to show how consumers can further reduce fuel bills. Another by-product of consumer awareness is increased demand for energy efficient applicances, cars, buildings, etc. Public demands may be sufficient incentive for industry to further research and develop more energy efficient products.

3. Evaluation of Energy Conservation Alternatives

The following questions arise regarding energy conservation proposals: What measures can local governments enact to implement an energy conservation plan? How effective can energy conservation be in terms of overall energy savings?

As a result of the energy crisis triggered by the Arab oil embargo, cities and local governments have, through necessity, become a forum of leadership for energy conservation legislation. A substantial concern is a " . . . public sense of returning to normal, i.e., wasteful energy consumption which signals a very great danger. If we are to avoid future energy deficits, it is imperative that continuing emphasis be placed on conservation."[93] "The potential for increasing the efficiency of energy consumption is substantial. This goal will be possible, however, only if a 'conservation ethic' can be developed by energy users and legislators."[94]

The question still remains what measures can local government enact to implement an energy conservation plan? Some suggestions are supplied by Dean Harold Williams of the Graduate School of Management of UCLA.[95] Local government, in order to

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[93] California Energy Planning Council; Calif. Energy Outlook 1974-1975 (June 1, 1974), p. 19.

[94] *Id.* at 22.

[95] Williams, Dr. Harold M., Energy Coordinator, Office of the Mayor, City of Los Angeles; Appraisal and Recommended Changes to the Emergency Energy Curtailment Plan (March 8, 1974), pp. 76-81.

implement both short and long term conservation action, could begin by enacting ordinances which would curb the waste of energy in all sectors by imposing percentage reductions in the use of energy and in substantial monetary penalties for failure to meet those standards.

The Emergency Energy Curtailment Plan (Ordinance No. 145, 350) which was enacted in Los Angeles to deal with the energy crisis in December 1973 is an example of a suggested ordinance for energy conservation. Local government should also provide for the encouragement of energy conservation measures. The possible proposals in this area are numerous, but a particular example could be the 4-day/40-hour workweek. The 4-day workweek may have a significant positive impact on gasoline consumption, natural gas consumption and electrical power use. The city should strive to implement a policy which would strike the optimum balance between energy needs and environmental requirements. Local government should also strive for more efficient urban planning in terms of long-term energy conservation. Further, local governments should consider legislating the labeling of all major appliances sold in their respective jurisdictions according to the appliance's efficiency in the use of electricity and annual operating cost. This would aid the consumer in his purchasing choices and habits, and have a long-term effect on the production of more efficient household appliances. There has been an architectural trend in recent years towards the design of buildings which require extensive use of energy. Local government building codes should be rewritten to conform with the policy of establishing energy

conservation criteria with respect to the design or construction of new buildings and the reconstruction of old buildings. Further, building codes should be modified with regard to insulation standards for residential construction. The feasibility of improving insulation in existing residences should be a major concern of local government.

Further recommendations for conservation are provided by Dr. Ron Doctor in his presentation to the Capital Improvements Committee of the City of Los Angeles Water and Power Commission on August 29, 1974. With regard to the transportation sector, airlines should be required to reduce speed, limit taxiing, and reduce flights by 10%. With regard to automobile transportation, further carpooling should be implemented and encouraged as well as the continuation of the 55 mile per hour speed limit. The residential sector should be encouraged to continue to reduce thermostat setting, to weatherstrip households, to maintain the residential heating plant, to turn out unneeded lights and use lower wattage light bulbs. The commercial sector should be required to change lighting and ventilation schedules as well as reduce lighting intensity. There should be a mandatory reduction in illuminated advertising, decorative lighting and night sports lighting. Industry should continue to administer and efficiently maintain thermal management programs to reduce energy consumption.

Assuming these policies were implemented, what results in terms of energy conservation can be expected? Fortunately, there is a large quantity of data available in this area. The following information was compiled by the Rand Corporation for

the Office of Conservation and Environment of the Federal Energy Administration. During the winter of 1973-74, the Los Angeles Department of Water & Power had a unique experience with electric energy. When the oil embargo was imposed, the Los Angeles Department of Water and Power found itself very short of oil for generating electricity. The Mayor and City Council responded very quickly to the crisis with the passage of the Emergency Energy Curtailment Plan. Under Phase I of the plan, residential and industrial customers were to cut use by 10%, and commercial customers were to cut use by 20% over the corresponding period of the year before. Under Phase II, residential use was restricted 12%, industrial use 16%, and commercial use 33% over the corresponding billing period a year before. The penalty for excess use was a surcharge of 50% on the entire bill for the first period violation, and a cutoff of service for subsequent violations. Savings in electrical energy consumption through customer response to the ordinance was rapid, and total use fell more than expected. Instead of the expected 12% reduction in Phase I, use fell off over 17% in the first two months that the ordinance was in effect.

The preliminary statistical analysis showed a rapid reduction in electrical use in all sectors, and especially in the commercial sector. The 17% energy consumption saving is even more significant in light of the 5 to 8.5 percent normal growth trend in electrical use which had been interrupted. Essentially, this means that the 17% figure is an absolute reduction, and when taken in conjunction with a 5%-8.5% normal growth trend, the resulting

saving totals an impressive 22%-25.5%.

Commercial sector use dropped even more significantly. Consumption by large commercial customers dropped 30% over the same month's use in 1973; that general reduction was being maintained in the summer of 1974 at approximately 20% below the monthly average for the summer of 1973. Some of the particular reasons for the adjustment, as well as measures taken to reduce electricity consumption, were outlined by the Rand Report. The findings indicated that: (1) lighting changes accounted for most of the reduced use; (2) most establishments regarded 20% as the reasonable amount to cut use without adverse consequences to their business; and, (3) most establishments are maintaining the reductions they made during the period the ordinance was in effect--both for economic reasons and because they decided they could operate as satisfactorily with less electricity.

The following charts indicate a breakdown of month-to-month savings recorded by the Los Angeles Dept. of Water and Power. The Emergency Energy Curtailment Plan was implemented in late December and was phased out in late May.

Table C-1

NET ENERGY FOR LOAD, 1973
(10,000 kwh)

Month	kwh	Percent Change
November	152	-0.1
December	143	-11.5
January	134	-17.5
February	119	-17.0
March	132	-15.9
April	128	-14.4
May	135	-13.2
June	144	-12.0
July	162	-5.2

CHART 1

Table C-4

SAMPLE OF 65 LARGE INDUSTRIAL CUSTOMERS
(% Change Winter 1973-74 vs. Winter 1972-73)

Month	Total Industrial	Oil	Aero-Space	Other
November	0.143	0.287	0.022	0.017
December	-0.251	-0.299	-0.311	-0.114
January	-0.148	-0.136	-0.198	-0.154
February	-0.202	-0.215	-0.216	-0.167
March	-0.181	-0.158	-0.242	-0.180
April	-0.132	-0.071	-0.212	-0.182
May	-0.169	-0.183	-0.191	-0.131
June	-0.040	0.148	-0.191	-0.211
July	-0.111	-0.052	-0.160	-0.186

CHART 2

Table C-5

SAMPLE OF 85 LARGE COMMERCIAL CUSTOMERS

(% Change Winter 1973-74 vs. Winter 1972-73)

Month	Total Commercial	General Merchandise	Apparel	Hotels	Office Building	Utilities	Hospitals	Public Administration	Education
November	0.0	0.01	-0.02	0.10	-0.01	-0.07	0.04	-0.06	0.03
December	-0.10	-0.20	-0.25	-0.09	-0.07	-0.13	-0.01	-0.24	-0.09
January	-0.25	-0.35	-0.43	-0.25	-0.29	-0.12	-0.12	-0.29	-0.26
February	-0.30	-0.44	-0.43	-0.24	-0.36	-0.17	-0.21	-0.38	-0.28
March	-0.29	-0.36	-0.43	-0.19	-0.36	-0.15	-0.23	-0.33	-0.28
April	-0.27	-0.35	-0.41	-0.21	-0.36	-0.18	-0.19	-0.37	-0.24
May	-0.25	-0.36	-0.41	-0.11	-0.29	-0.16	-0.18	-0.34	-0.23
June	-0.27	-0.43	-0.40	-0.17	-0.28	-0.01	-0.20	-0.31	-0.34
July	-0.21	-0.21	-0.34	-0.17	-0.24	-0.06	-0.17	-0.27	-0.20

CHART 3

With regard to conservation in local government operations, a newsletter of the National Association of Counties, dated January 15, 1975, indicated substantial savings for Los Angeles County. As a result of a wide-ranging conservation policy adopted for all departments, Los Angeles County reported savings of:

--11.4 million kilowatts of electricity each month or $200,000 per month (a 20-25% cut in consumption)

--100,000 gallons of gasoline per month or $37,000 to $40,000 (a 12% cut)

--50 million cubic feet of natural gas per month or $40,000 to $50,000 (a 20% cut)

Further evidence of Los Angeles County's substantial savings comes from Dr. Doctor's comments before the Capital Improvements Committee on August 29, 1974, supra.

> The County of Los Angeles took vigorous action in their own buildings because they didn't have jurisdiction over the users of electricity outside the City. So, they took action in their own buildings. Now, the County operates some 1700 buildings throughout the L. A. County, buildings of all types; generally, they fall into the commercial and government classifications. . . . The savings are substantial, more substantial than the 15 percent reduction that I've very conservatively assumed here.

These reflect solely governmental savings through more efficient guidelines regarding consumption. It is arguable that the private sector could do as well.

Data compiled by the California Energy Planning Council, in January of 1974, supra, reflected studies made in California

statewide regarding energy conservation. The first quarter (January, February and March) of 1974 was used as the test period as to gasoline and natural gas consumption in California. Certainly this cannot be considered a comprehensive statement on energy conservation, but the study can give reliable indications for the effectiveness of energy conservation. The focus of the study was to weigh the value and measure the effectiveness of specificied conservation measures. With respect to gasoline consumption, the policies tested were: (1) a reduction of maximum speed limits to 55 miles per hour; (2) reduced automobile travel (assumptions as to reduced automobile travel were based on data from the monthly gasoline sales of the State Board of Equalization and adjusted by the tax refund data from the Office of the State Controller).

The chart below reflects California gasoline consumption during the first quarter of 1974. It reveals a total net savings of over 225 million gallons of gasoline, which represents a 9 1/2 percent reduction in gasoline consumption as compared with the same time period in 1973. The report describes the tabulation of the year-to-year gasoline consumption reduction between reduced speed and less driving. Those figures are based on state calculations.[96] This data indicates that of the total quarter savings of 9 1/2 percent, approximately 3 percent of this is attributable to lowered speeds and 6 percent to reduced travel.

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[96] California Dept. of Transportation; Observed Facts of the 55 miles per hour Speed Limit ; (March 29, 1974).

CALIFORNIA GASOLINE CONSUMPTION
First Quarter 1973 & 1974
(millions of gallons)

	1973 (1)	1974 (2)	Year-to-Year reduction (3)	%
Jan.	789.6	735.5	54.1	6.85
Feb.	739.2	673.8	65.4	8.85
Mar.	852.1	745.7	106.4	12.5
Qtr.	2380.9	2155.0	225.9	9.5

CHART 4

With respect to natural gas, the following data is provided for the months during which gas consumption is normally the heaviest.[97]

CALIFORNIA PERCENTAGE REDUCTION
IN CONSUMPTION OF NATURAL GAS
(Nov. '73 - Mar. '74)

Utility	1973		1974			5 mo. Avg	Millions Customers End of '73	% of Total	Weighted % of State Total Reduction
	Nov	Dec	Jan	Feb	Mar				
PG&E	4.3	14.9	5.3	6.1	3.5	6.8	2.444	39.86	2.71
SCE	.3	5.2	8.4	8.0	8.4	6.0	.409	6.67	.41
SDG&E	5.6	11.8	10.5	8.8	N/A	9.2*1	3.279	55.47	4.92
Totals	State Average *2						6.132	100	8.04

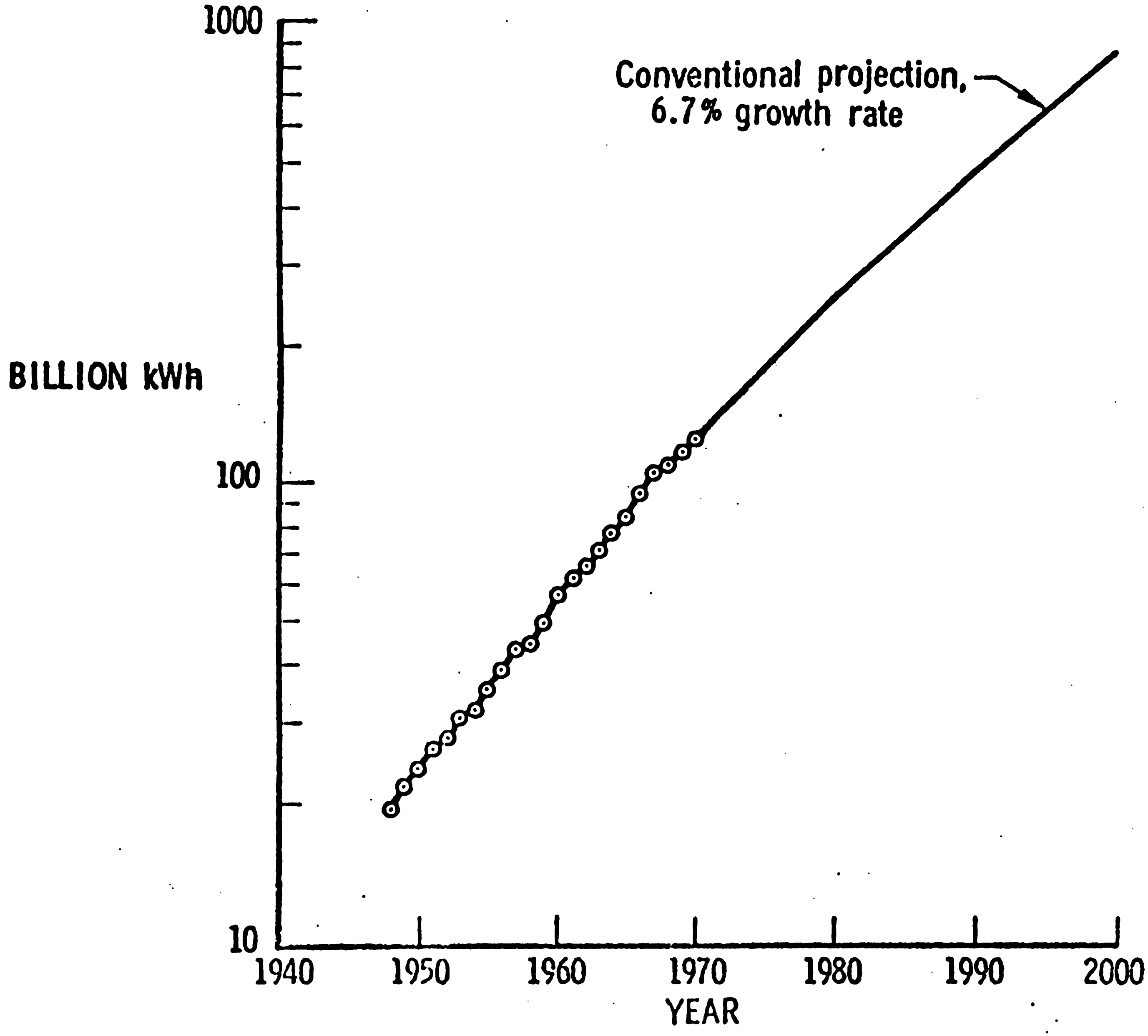
* Approximately 97% of State
*1 Four month average
*2 Approximately 99% of State

CHART 5

97 California Public Utilities Data. The data was adjusted for year to year weather variations before percentages were computed. They show the reduction from estimates of consumption, had no conservation program been in effect and had gas supplies not been limited.

The following graphs were prepared and presented by Dr. R. E. Doctor to the Capital Improvements Committee of the Los Angeles City Water and Power Commission on August 29, 1974. They support many of the statements made above and give a broad overview of energy factors leading to support of strong conservation measures. Note especially the historical and projected growth rate in California energy consumption, data with regard to energy use of buildings and the need for building code legislation, and data with regard to transportation and the need to develop public mass rapid transit.

CALIFORNIA ELECTRICITY PROJECTIONS



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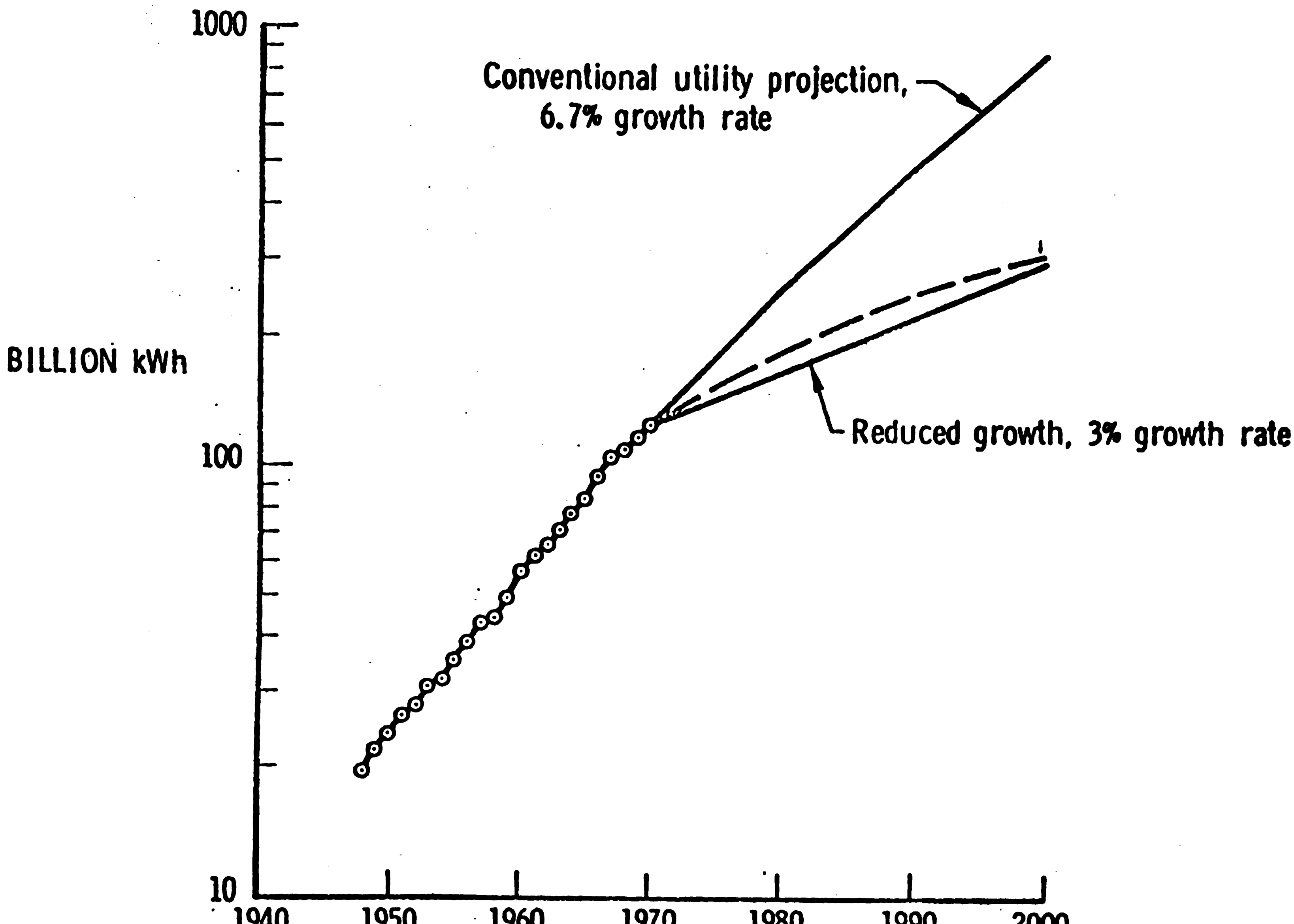
Santa Monica, Calif.

CALIFORNIA ELECTRICITY PROJECTIONS



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Santa Monica, Calif.

ENERGY USE IN CALIFORNIA (1971)*

SECTOR	TRILLION Btu	EQUIVALENT** BARRELS OF OIL PER DAY	% OF TOTAL
INDUSTRIAL	1944	918,000	33.3
TRANSPORTATION	1968	930,000	33.8
RESIDENTIAL	1108	523,000	19.0
COMMERCIAL	811	383,000	13.9
TOTAL	5831	2,750,000	100.0

* Military and other uses and electricity have been distributed to the other sectors

** Conversion factor used is 5.8 trillion Btu per barrel of oil

The Rand Corporation
Santa Monica, CA.

COMMERCIAL SECTOR — HIGH RISE BUILDINGS

- LIGHTING ACCOUNTS FOR ABOUT 45% OF THE BUILDING ENERGY

  - 70% OF BUILDING ENERGY GOES FOR HEATING, VENTILATING AND AIR CONDITIONING (HVAC)

  - 75% OF HVAC IS DUE TO INTERNAL SOURCES (PEOPLE, LIGHTING, MACHINES)

  - 85% OF INTERNAL HEAT LOAD IS DUE TO LIGHTING

The Rand Corporation
Santa Monica, CA.

SOME DESIGN AND OPERATION EFFECTS
(L.A. OFFICE BUILDING)

	ENERGY—THOUSAND BTU/SQ FT			
	COOLING	HEATING	COOLING + HEATING	PRIMARY ENERGY
NOMINAL	88	15	103	256
24 HR LIGHTING	137	4	141	414

The Rand Corporation
Santa Monica, CA.

TRANSPORTATION SECTOR

- 75% OF TRANSPORTATION ENERGY IS FOR HIGHWAY VEHICLES
  - 51% FOR AUTOS
  - 22% FOR TRUCKS
  - 1% FOR BUSES

- 14% OF TRANSPORTATION ENERGY USED IN AIR TRAVEL

The Rand Corporation
Santa Monica, CA.

HIGHWAY USE OF FUEL IN CALIFORNIA

- HIGHWAY USES CONSUME ALMOST 10 BILLION GALLONS OF GASOLINE AND DIESEL FUEL ANNUALLY (650,000 bpd)

- 75% OF HIGHWAY FUEL IS CONSUMED BY 10 MILLION AUTOS

- 20% OF HIGHWAY FUEL IS CONSUMED BY 2 MILLION TRUCKS

The Rand Corporation
Santa Monica, CA.

SHORT TERM ENERGY CONSERVATION POTENTIAL FOR CALIFORNIA*

SECTOR	CONSERVATION MEASURES	ESTIMATED MAXIMUM SAVINGS (Equivalent Barrels Per Day)
TRANSPORTATION	1. Airlines reduce speed, limit taxiing, reduce flights by 10%	11,000 – 14,000
	2. Carpooling	39,000 – 80,000
	3. 55 mph speed limit	11,000 – 22,000
RESIDENTIAL	4. Reduce thermostat settings	92,000 – 118,000
	5. Weather strip households	35,000 – 58,000
	6. Keep heating plant maintained	13,000 – 20,000
	7. Turn out unneeded lights, use lower wattage light bulbs	8,000 – 11,000
COMMERCIAL	8. Change indoor building lighting and ventilation schedules. Reduce lighting intensity	83,000 – 140,000
	9. Reduce illuminated advertising, decorative lighting, night sports lighting	6,000 – 12,000
INDUSTRY	10. Thermal management programs	50,000 – 99,000
TOTAL POTENTIAL SAVINGS**		340,000 – 540,000
		11-18% of 1973 consumption

* Based on the President's energy conservation recommendations

** Corrected for non-additive effects

The Rand Corporation, Santa Monica, CA.

Short term achievements in energy conservation have been impressive. Credit should be given to both the public and the private sectors. The danger lies in a possible relaxation of the conservation effort due to a false sense of well-being. Several scientists and educators have recognized the need for, and importance of, a strong energy conservation policy.

In his presentation of testimony to the Capital Improvements Committee of the Los Angeles City Water & Power Commission on August 29, 1974, Dr. R. P. Doctor stated:

> The United States growth rate in overall energy demand must be reduced. If it is not reduced, then over the next 25 years, we can expect to experience increasingly severe energy shortages, environmental disruption and serious economic dislocation. The recent studies at Rand and elsewhere indicate quite clearly that it is possible to reduce future energy demands substantially by reducing the wasteful uses of energy, not by cutting to the bone but by reducing waste; that these reductions can be achieved with little or no disruption in our economy, that on the contrary, effective implementation of emergency conservation measures can lead to very significant economic benefits.

Dr. Robert Williams, senior scientist with the Ford Foundation Energy Policy Project in Washington, D. C.,in testimony before the Capital Improvements Committee of the Los Angeles City Water and Power Commission on August 29, 1974,stated:

> Our studies indicate that with the historical growth road to the future, the country will have to invest something like one and three-quarter billion dollars in the energy industry over the next 25 years in order to meet that

growth curve. If substantial energy conservation measures were put into effect, you should be able to save something on the order of 300 billion dollars over that period, and that, incidentally, takes into account the added capital requirements for the capital equipment necessary to bring on line energy conservation equipment.

In his speech, "We Must Break the O.P.E.C. Cartel", made before the Federal Energy Administration in San Francisco, California on October 10, 1974, Dr. Harold M. Williams, Dean, Graduate School of Management, UCLA, stated:

Our energy policy until now has been one of response to crisis and pressure groups. In the recent past, we have gone from a primary concern over the environment to one of conservation to survive the Arab embargo, to one of finding ways to increase supply and recycle dollars. It is now the time that we evaluate our position, clearly define our problems and needs, determine the results we must accomplish, and the behavior we need to encourage, evaluate the social and economic trade offs and establish a comprehensive program with both short and long-term dimensions. The short-term objectives of the program must be geared to an immediately effective and tightly implemented program of energy conservation. It is perhaps more vital that we decrease consumption than we increase domestic production. We suffer less from energy shortage than we do from excess energy consumption. As a result, fuel conservation has very little to do with economic growth. We are talking about the elimination of totally unnecessary waste to which all of us contribute and which could quickly be reduced to the point where the price for oil producing exporting countries' oil would have to reflect a drastically lowered demand and where the price fixing coalition would find it difficult to continue their production or to allocate cutbacks.

4. Conclusion

The underlying premise for these proposals is that it is economically and technically feasible to reduce the energy growth rate to a long term average of 2%. An energy conservation policy would benefit major areas of concern--industrial growth, national energy independence, employment opportunities, preservation of limited valuable resources and protection of the environment.

The energy shortage is man-made, a product of past U.S. policies and lifestyles. In the past, government has not considered the long term or, in most cases, even the short term consequences of promoting ever increasing energy use except as measured by economic profits. The energy shortage and government neglect need not continue indefinitely if corrective measures are adopted now.

A decisive energy policy integrated with energy saving measures can reconcile an apparent conflict between continued economic prosperity and finite fuel resources. Fuel efficient vehicles, mass transit, thermal insulated commercial and residential buildings, recycling programs, heat recovery processes in industrial practices, etc., are just a few of the potential measures which can be implemented on a short term basis to help conserve energy. Coupled with fuel efficiency, research and development of new sources of energy is the key to greater flexibility and national independence.

This vigorous energy conservation plan offers a viable, realistic and practical alternative to accelerated exploitation of this nation's limited fossil fuels. One ramification of energy conservation is that fuel economy savings can be realized within a short time period. More importantly, the savings have been shown to be substantial without impairing industrial growth or displacing employment opportunities. The Southern California Council believes, in its judgment, that energy conservation is a far wiser and socially valuable decision than accelerated O.C.S. leasing.

D. Exploration of Other Energy Alternatives

The E.I.S. concentrates on the production of O.C.S. oil and gas as the primary source for meeting the nation's energy needs. Yet many viable energy alternatives are available to supplement the current domestic use of hydrocarbon fuels. These alternatives, which were not adequately examined in the E.I.S., include such energy sources as solar, wind, nuclear, geothermal, bioenergy, conversion of solid waste, oil shale and the increased use of hydro-electric power. The primary reason for the development of these alternative sources are the relatively slight adverse environmental impacts, low cost, and abundance of each of these power sources.

Two exceptionally promising new fields of energy are solar and geothermal. California is in a unique position in terms of the availability of these resources. Solar energy is described in the draft E.I.S. as a renewable resource which lacks many of the adverse environmental impacts associated with fossil fuel extractions. Its uses are limitless and among the applications now under development are solar heating, baking, solar power plants, cooking, furnaces, solar pumps and turbines, and solar sewage treatment.

The importance of solar energy has been recognized by several national organizations and scientists. The National Science Foundation in <u>Solar Energy as a National Energy Resource</u> at page 13 stated,"Solar energy is an essentially inexhaustible source potentially capable of meeting a significant portion

of the nation's future energy needs with a minimum of adverse environmental consequences. The indications are that solar energy is the most promising of the unconventional energy sources." The noted physicist, Dr. Arthur R. Tamplin, in June, 1973 issue of Environment, concluded, "Solar energy represents a pollution free and non-resource depleting source of energy in the near future. With an adequate program only modestly expensive when compared to today's standards (before increases in oil prices), this source of energy could be utilized in economically competitive fashion."

The following are among the conclusions and recommendations of the Solar Energy Panel of the American Society of Mechanical Engineers which met in Nov., 1973: "Solar Energy is received in sufficient quantity to make a major contribution to the future U.S. heat and power requirements. There are no technical barriers to wide application of solar energy to meet U.S. needs. For most applications the cost of converting solar energy to useful forms of energy is now higher than conventional sources, but due to increasing prices of conventional fuels and increasing constraints on their use it will become competitive in the near future."

The draft E.I.S. has taken issue with this point, arguing that solar systems are not economically competitive on a significant scale because of the initially greater investment for solar heating in comparison with conventional systems. One reason that solar power may not be at a more advanced stage is the large investment by major oil companies in conventional

sources of energy with greater potential for immediate profit and development. The draft E.I.S., citing Westinghouse Electric Corporation, states that government programs and incentives will be required to close the gap between near term costs for solar systems and additional costs consumers will be willing to pay.

Yet cost evaluation of a solar heating system should not be done on an initial cost basis, but rather on a life cycle cost basis. In their Energy Element, the California Coastal Zone Conservation Commission at page 121 finds that capital investment in a prototype domestic solar energy collector house has been demonstrated to be somewhat higher than a conventional house design, yet it is expected that the production models could reduce the construction cost. Also, there are several long term economic operating advantages over conventional house design: (a) both cooling and heating are accomplished through utilization of low cost solar energy collectors. (b) the solar energy system components and the heating and cooling systems are compatible with each other and are integrated in a total systems concept, and (c) the buildings as well as the mechanical and electrical systems are initially designed and constructed to conserve energy. The draft E.I.S. acknowledges that extensive application for solar power does exist today in home heating and cooling and water heating, using relatively inexpensive collectors.

The South Coast Regional Commission, part of the State Coastal Zone Commission, finds that the Southern California region lies in a particularly favorable location for mean daily

solar radiation. Moreover, in a large area of Southern California, over two-thirds of the natural gas consumed directly in space and water heating could be saved by the use of solar energy. On a month to month basis, the share of space and water heating provided by solar energy can be expected to range from 50% to 80%. Because solar energy can supply the major share of energy for space and water heating on a year around basis, utilization of solar energy can directly reduce the growth in base load demand for natural gas. A corresponding reduction in requirements for a new gas supply would also be indicated. Alternatively, more natural gas could be burned in the region's electric generating plant.

A second major new energy alternative is geothermal energy. Geothermal power is an indigenous source of energy which has a long term capability, does not utilize scarce fossil fuels, and can be relatively non-polluting. According to the California Coastal Zone Conservation Commission's energy element, geothermal potential in California is significant. There are 35 potential geothermal resource areas covering more than 15 million acres within California. Sixteen of these are "known geothermal resource areas", that is, the presence of geothermal resources has been verified. Geysers Field in California has been producing geothermal power since 1960.

The draft E.I.S. in its brief discussion of geothermal power mentions the pollution problems of geothermal energy, such as adverse air quality impacts and problems of waste water disposal. We agree that additional research is needed but there are

proposed methods to bypass many of the problems associated with geothermal energy. One method uses thermo-electric devices that would obtain electricity directly from the heat source with very slight environmental danger. Another method, the down hole heat exchanger, which theoretically would eliminate all the major difficulties with geothermal exploration, would make geothermal energy available in more locations and would provide an inexpensive, abundant, accessible source of power.

Although relatively few geothermal fields are currently developed, where there is a hint of a new geothermal field, the land above almost always has been leased to a petroleum company, a fact which reflects the potential of this new energy source.

Increased nuclear power is mentioned in the Environmental Impact Statement as an alternative energy source, but both the beneficial use and the existing environmental problems are inadequately discussed. The President's Council on Environmental Quality in their report on O.C.S. development states that "Nuclear energy will play a growing role in the Nation's energy supply between now and the year 2000. By 1985, nuclear energy is expected to increase to about 30% of the total net electrical energy, and by 2000 almost 70%." (page 3-24)

The electric utilities in the South Coast region, according to the Coast Regional Commission of the California Coastal Zone Conservation Commission believe that nuclear power plants will provide the lowest cost and most certain source of electrical energy to meet the growth and demand which they have forecast for

the remainder of the century. Base load nuclear power plants would also be able to provide low cost off-peak power necessary to make pump storage facilities economical. The utilities also believe that the environmental impacts of nuclear power plants are, all factors considered, less than those of fossil fuel plants and also that nuclear fuel supplies are more assured than those for the petroleum-fired plants.

The environmental impacts of a large scale power plant are substantial. Nuclear power plants pose a safety hazard to population centers in the region due to the danger of damage to the facilities and resulting release of radioactive materials to the environment. A second problem is that of the heated waste water. When these thermal pollutants are discharged in the ocean, they have a disputed and still somewhat unknown effect on marine organisms. To control radioactive emissions, nuclear plants are designed to minimize accidents and their adverse effects, utilizing a "defense in depth" principle. This design includes setting reactors in remote areas as well as designing and constructing plants to prevent accidents and to contain the effects of accidents should they occur.

Radioactive waste storage, however, is a very significant problem. Because of the high concentrations of radioactive nucleides and very slow rates of decay, the waste materials must be isolated from the biosphere for hundreds of thousands of years if adverse effects to living organisms are to be totally avoided. Waste is presently being stored in below-the-surface man-made

storage facilities. Research is being conducted to find a permanent storage depository. As part of this research, pilot studies of storage in salt beds are being conducted.

According to the California Coastal Zone Conservation Commission, there are no coastal sites in the South Coast Region which would currently meet the Atomic Energy Commission's population density standards except for the western portion of Malibu, which has already been found not to meet the A.E.C.'s seismic activity standards, and the Channel Islands, which are areas of particularly great biological significance to the region.

Project Independence Blueprint points out that public acceptance of nuclear power is an important factor in overcoming the current problems constraining the use of nuclear power and the exploration and mining of uranium. Utility planning, site availability, licensing schedules, and implementation of measures to shorten the construction period are all influenced by public acceptance.

Nuclear power generation, however, has important advantages in being relatively insensitive to location of fuel sources because of low nuclear fuel transportation costs. Nuclear power may also be more environmentally acceptable than coal or O.C.S. drilling, provided that fears of nuclear accidents can be alleviated.

Generation of electricity through hydroelectric developments has generally been recognized as a renewable resource that does not directly cause air pollution. An environmental problem has been encountered with running river power plants, however, in that the use of streams for power will displace some forms of recreational activities and eliminate vast areas for land use. There is

also a very limited number of areas appropriate for hydroelectric plants. Therefore, the utilization of storage projects should be increased.

Pumped storage projects generate electric power for releasing water from an upper to a lower storage pool, then pumping the water back to the upper pool for repeated use. During off-peak hours when project capacity is not required by the system, water is pumped to the upper pool using energy generated by other sources such as large modern steam turbine electric units. Its economic advantage comes from converting low cost, low value off-peak energy to high value peak capacity energy.

Another viable but less publicized energy alternative is that of wind. Energy can be obtained from the wind by means of a device which extracts energy from a moving mass of air. That is, a fixed device can capture kinetic energy by rotation about an axis and, coupled to a generator, convert it into electricity. This alternate energy source was not discussed in the draft E.I.S. Wind energy is in use at various locations all over the world, providing substantial amounts of energy. The advantages in using wind energy are the following: inexhaustible supply, worldwide availability, free on-the-site production, and few adverse environmental impacts. The environmental problems that do exist are those of minor aesthetic and noise pollution from wind mills. The aesthetic design problems can occur in either very large windmills or a proliferation of small ones. With proper design attention, neither problem appears insurmountable. Both large and small windmills can be attractive in design. The open sea is probably

a better location for the larger windmills as noise pollution would not be a problem and the winds are steadier.

The principal drawback to wind power is the variable nature of the wind's energy as great fluctuations in wind velocity make consistent generator operation difficult. Even in very windy locations, slack wind periods occur. Therefore, some method for storing energy must be an integral part of most wind power generation schemes.

In sum, wind generators today could be an important source of electric energy in this country had not their technological development been virtually halted as a result of the gasoline engine. Unlike fossil fuel and atomic power sources, the windmill consumes no non-renewable resources and causes no atmospheric pollution or thermal pollution. It has positive aesthetic features in eliminating power lines as well as a beauty of its own. Wind energy could be a principal contributor of power in a mixed system and has the potential, depending on advances in the state of the art, of being a major regional and even a national energy source.

Shale oil is another alternative which is inadequately discussed in the E.I.S. This viscous petroleum, material extracted from maristone rock, can be refined into a complete line of petroleum products by conventional refining techniques. Although it is not possible precisely to predict the level of production or the technology that may be used, it is possible to establish a range of possibilities. According to Project Independence Blueprint, with a world oil price of $11.00 per barrel, the estimated oil investment would be about 20%. Moreover, certain government actions coupled with

a stable price of $11.00 would create the economic and institutional climate necessary to achieve higher levels of production. Under these conditions, according to Project Independence Blueprint, production levels of one million barrels per day could be attained by 1985.

Shale oil production, however, does affect the environment. At production levels above 200,000 to 300,000 barrels per day, emission from surface shale plants are expected to exceed the 1980 standards of 10 micrograms of sulfur dioxide per cubic meter. Further, the quantities of water used and the plant effluents could affect local water acquifier pressures and the water quality.

Another potential energy source which was not discussed in the draft E.I.S. is that of bioenergy. From organic waste, three forms of energy can be produced: natural methane gas from organic decay, oil from organic waste through chemical processes and the production of alcohol from crops through fermentation. According to the B.L.M. in their publication "Energy Alternatives and Their Related Environmental Impact", at page 379, the processes are as follows: agricultural land would grow cereal grains which are largely carbohydrates and then convert these grains by fermentation into ethyl alcohol, which is a convenient combustible fuel readily usable in motors. If we assume that the 100 million acres (or about one half of the acres not now required) are used to produce the grain for alcohol at a yield of 70 bushels per acre, this would be equivalent to about 18 billion gallons of alcohol or over 20% by volume of the 86 billion gallons of motor fuel consumed in the United States in 1970. To produce

oil from agricultural waste, the organic material is treated with carbon and water and then heated under pressure. According to data from the Bureau of Mines, 1971 collectible agricultural residues in the United States amounted to over 130 million tons annually with an oil potential of 170 million barrels, roughly equivalent to 47 million tons of low sulphur coal. The production of natural methane gas from organic waste is relatively easy as the gas is generated through the natural process of decay of the mass of waste and one simply has to tap and regulate this gas to provide a pollution free and inexpensive source of fuel.

The State Coastal Zone Commission's study on energy illustrates that the potential from waste is significant. In 1970 Californians produced 75 million tons of solid waste, about one half of which can be considered to be readily collected organic types of waste than can be used for energy production. In a study done by Stanford Research Institute for Pacific Gas and Electric, the Institute concludes that refuse could furnish about 10% of the fuel needed by utilities at prices competitive with other power generation fuels. This process has doubled advantages: it produces energy while solving very difficult land use and solid waste management problems.

Finally, as an alternative to increased domestic drilling on the O.C.S., we should not discount the current practice of oil and natural gas importation. This practice is currently under discussion and is being evaluated through both <u>Project Independence Blueprint</u>, the domestic energy self-

sufficiency program, and President Ford's new energy policy announced January 15. All future determinations regarding major changes in our national energy supply demand programs should await the final evaluation of these programs.

In conclusion, a Special House Democratic Task Force Report on New Sources of Energy (Jan. 13, 1975) states that "The long-term solution must of necessity feature the earliest possible development of energy alternatives to petroleum. This concentrated effort should include the rapid perfection of economically viable methods of coal conversion and levels of funding adequate to accelerate pure and applied research in solar energy, nuclear fusion, geothermal power, the environmentally acceptable recovery of oil from shale and any other alternatives that committees may choose to consider."

E. PRODUCTION OF SHUT-IN WELLS AND SECONDARY AND TERTIARY RECOVERY AS ALTERNATIVES TO EXPANDED O.C.S. DEVELOPMENT

1. Shut-In Leases

Recently, the House Subcommittee on Regulatory Agencies has brought to public attention an allegation that oil and gas producers are actively withholding producible O.C.S. leases off the Gulf of Mexico. A number of producible tracts (185 in 1973, and 168 in 1974) have been classified as "shut-in" by the U.S.G.S. after application by the oil and gas companies. The procedures of U.S.G.S. allow such a classification, and permit a regional U.S.G.S. supervising engineer to grant such a classification based upon "a matter of judgment".

It has been estimated by the Federal Power Commission (hereinafter referred to as the F.P.C.) that 168 fields off of the Gulf of Mexico are capable of producing both oil and gas in large quantities. The Western Oil and Gas Association responded to the charges, claiming that mechanical problems, lack of producing facilities, etc., were the reasons for seeking the classifications.

The recent House Subcommittee investigation, however, found that, though some of the reasons were legitimate, in the majority of instances the classification of "producible shut-in leases" was sought as a means of

holding on to a lease beyond the original primary term of five years. One obvious benefit of such a maneuver is to allow oil and gas companies to produce valuable resources in the future when demand-market prices have increased.

The shut-in classification compounds the problem of estimating resource reserves. In order to classify an entire lease (which involves a tract of approximately 9 square miles), the petroleum producer need only drill one well capable of producing resources in paying quantities. All too often, the one well is located in only one of many reservoirs located on the tract. Because further drilling would result in the loss of the shut-in classification, oil producers prefer not to explore the possibility of further resources until sometime in the future.

A cornerstone to the formulation of a rational, cohesive, and long term energy policy is knowledge of the nation's resources. Without such data, it is impossible to establish a plan that can systematically meet future demands with limited fossil fuel resources.

During the House Subcommittee investigation, one witness from the F.P.C. indicated that American Gas Association estimates of natural gas should have been 54% higher. Such discrepancies in resource estimates adversely affect long term energy plans and shift the burden of higher costs to the consumer.

Based upon evidence and testimony presented,

the House Subcommittee found that the decision to lease 10 million acres per year is not rationally related to the nation's energy supply and demand projections. In fact, the Subcommittee has been unsuccessful in determining how the Department of the Interior arrived at such a figure.

Another issue raised by shut-in leases is the ability to develop the O.C.S. If oil and gas companies are unable to meet present production schedules because of the lack of manpower, drilling rigs, pipelines, geological evaluations, etc., how can the oil companies expect to meet the demands of an accelerated O.C.S. leasing program?

During its hearings, the Subcommittee heard testimony from an oil company executive who could not offer any assurances that the oil companies could meet the challenge of an expanded leasing program with sufficient numbers of trained personnel and equipment. If oil and gas companies are unable to develop the proposed 10 million acres, then what basis is there for leasing the land at this time?

(a) What is a Shut-In Lease?

A producible shut-in lease (gas and/or oil) is defined as a lease in which at least one well has been drilled and has been determined to be capable of being produced in paying quantities and for which a suspension of production or operations has been approved by a U.S.G.S. supervisor.

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[98] Permanent Select Committee on Small Businesses, "A Report on the Activities of the Subcommittee on Regulatory Agencies;" Energy Data Requirements of the Federal Government: Part I, Part II, Part III, Part IV, Testimony of Ralph A. Johnson; 93rd Congress 2nd Session (December 30, 1974). Herein after cited as Energy Data.

In contrast, a shut-in completion is a well that was drilled and produced, and thus classified as being no longer capable of production or its resources having been depleted.[99]

At the present time there appears to be a great deal of controversy over the definition of "shut-in". In a recent press release,[100] it was explained that "until 1972 the statistics on shut-in well completions did not include wells left standing due to drilling on platforms, planning for secondary or other injection projects, delays in facilities, well-plugging by sand, mechanical problems, pressure depletion, or having an excessive-oil ratio. These well completions were considered 'active' because they were neither plugged with cement and finally abandoned, nor under current application for approval of workover or repair projects."

The controversy involves the apparent increase in "non-producing" oil well completions in the Gulf of Mexico from 942 in 1971 to 2,978 in 1972; and from 602 to 872 for gas well completions.[101] The Department of the Interior claimed that the increase was not due to an actual rise in

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[99] Leonard L. Silver comments in a telephone conversation with the Los Angeles City Attorneys Office, January 10, 1974.

[100] Department of Interior, Press Release, December, 1974. ✓

[101] Energy Data, supra n. 98, at 134. Testimony of George L. Donkin.

shut-in wells, but rather a change in the method of reporting statistics on oil and gas wells by the U.S.G.S.[102]

Unfortunately, the Department of the Interior's explanation merely serves to confuse and obliterate the real issues in question. For instance, one questions the logic of labeling a well "producible shut-in" if it is incapable of producing because of insufficient platforms, and facilities, pressure depletion, or a well plugging by sand as a "producible shut-in".

The purpose of the "producible shut-in lease" classification is to enable the lease, in the absence of actual production, to be extended beyond its primary term of five years. U.S.G.S. Outer Continental Shelf Order No. 4 authorizes the lease extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. A well may be found to be capable of production in paying quantities when: (a) a production test of the well indicates that its production capability meets the requirements of the order. The U.S.G.S. District Engineer determines whether or not a well is capable of producing in paying quantities. No payment formula per se is used in the U.S.G.S. determination. The well which qualifies the lease as a producible shut-in may or may not be classified as a shut-in well itself;[103] (b) an outer continental shelf lease may be maintained beyond the primary terms, in the absence of actual

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[102] Id. at 134.

[103] Energy Data, supra n. 98, at 112 Testimony of Ralph A. Johnson.

production, when a suspension of operations or production, or both, have been approved and; (c) the supervisor may approve a suspension of production, provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities.

There are additional procedures by which oil companies may hold leases in nonproductive capacity. In addition to "producible shut-in leases", there are other technical classifications which may be used. First, under the Outer Continental Shelf Lands Act of 1953, the regional U.S.G.S. supervisor is authorized to unitize leases on a field-wide basis. Companies wishing to combine two or more O.C.S. leases must submit to the U.S.G.S. an initial plan of development which, if approved, extends the acreage in a "producible shut-in" status. Under this plan it is possible for a single producible well to hold a number of leases for years beyond their primary term.[104]

Secondly, the regional supervisor also has the authority to consolidate two or more leases into production units even though only one of the unitization leases is actually producing oil or gas. Again, all leases under the unitization agreement are given extensions beyond their primary terms.[105]

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[104] Id. at 134. Testimony of George L. Donkin.

[105] Id. at 134.

The present classification procedure for producible shut-in leases has adversely affected the government's ability to efficiently administer O.C.S. leasing. A recent F.P.C. study indicates the continuing problems presented by the shut-in classification. The study, entitled "Offshore Investigation: Producible Shut-In Leases (First Phase), January, 1974, and March, 1974", provides some interesting insights into the issue of shut-in leases.

The F.P.C. study set forth ten common reasons for seeking producible shut-in classification: (1) preparing development plan; (2) waiting on platform production, or pipeline facilities; (3) waiting on market or marketing facilities; (4) waiting on completion of drilling program and/or evaluating geological and geophysical data in order to prepare development plan; (5) preparing economic evaluation, (leases considered marginal by operator at present established wellhead prices); (6) waiting on, or preparing evaluation of, drilling results on adjacent leases; (7) waiting on rig drilling equipment; (8) preparing development plans for economic evaluation after physical damage to production facilities (hurricane, fire, etc., damage); (9) no reason reported; and (10) waiting on F.P.C. certificates.[106]

The next to the last reason given is particularly interesting in view of the requirement that a U.S.G.S.

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[106] *Id.* at 30

supervising engineer approve a classification request for a producible shut-in lease. The House Subcommittee stated that: "Approval of such a request for a shut-in with no reason given would indicate confirmation of other reports that U.S.G.S. lease management and supervision of operations on existing leases was deficient. Beyond the possibility of lax supervision of producing leases, this study (F.P.C. study) indicated the possibility that even the most rudimentary examination of a lease operation did not take place and leases could be extended without any reason being given by the lease owner or required by U.S.G.S. Order No. 4."[107]

The mismanagement of shut-in leases is only one of many findings that the Subcommittee made. The Subcommittee states, for example, that the Department of the Interior has not demonstrated the capability to efficiently administer the present leasing program. The Subcommittee also questioned the Department's ability to meet the challenge of an accelerated program. The Subcommittee points to inadequate resource evaluations, inequitable bidding systems and the lack of any systematic procedures for sound decisionmaking.[108]

Although the Department of the Interior is responsible for the management of shut-in leases, the oil companies are not innocent beneficiaries. They have continued to take advantage of regulatory loopholes and lax Department of the

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[107] Id. at 30

[108] Id. at 30

Interior supervision. In order to justify some of their requests for producible shut-in leases, industry has pointed to lack of facilities and platforms, or waiting for completion of an oil program as posing obstacles in their attempts to "farm" the tract in question. Some reasons offered by the oil companies are valid and do prevent the oil companies from producing at full capacity. Yet mechanical problems or delay in facilities should have been resolved within a short period of time.[109]

The House Subcommittee investigation suggested that producers were "not responding to current price levels but rather to anticipated higher prices."[110] As one individual testified, "Producers prefer to speculate that price increases in the future will result in higher returns than commitment of new supplies at current price levels."[111]

In January, 1973, B.L.M. records indicated there were 185 O.C.S. shut-in oil and gas leases offshore Texas and Louisiana. These leases constituted a total of 838,477 acres for which bonuses of $972,000,000 were paid.[112]

Even if industry could disprove "anticipatory pricing", the reason stated for seeking the producible shut-in classification raises the issue of preparedness. If, under the existing lease system, oil companies do not have pipeline or production facilities or the time and manpower to evaluate geological and physical data in order to prepare

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[109] Id. at 112. Testimony of Ralph A. Johnson.

[110] Id. at 114.

[111] Id. at 114.

[112] Letter to Mr. Norm H. Emerson From Professor Paul Davidson, University of Rutgers, December 19, 1974 at 2.

present development plans, then one must seriously question the company's ability to develop the proposed 10 million acres that the Department of the Interior now wishes to lease.

The present shut-in classification system also impairs government's ability to formulate a rational, cohesive, long-term energy policy because of unknown resource supplies. The Department of the Interior relies upon industry estimates of potential resources. Without independent resource data, the Department of the Interior is unable to fully evaluate industry projections. Thus, an unknown reserve of gas and/or oil is created about which the U.S.G.S. has no knowledge.

The problem is magnified if numerous tracts are brought together under a unitization proposal. Here, only one well in one tract is needed to qualify numerous leases for a shut-in classification. The projected capacity for the other tracts involved is completely unknown. Therefore, U.S.G.S. has no ability to gather or evaluate data as to potential reserves of oil and gas.[113]

In the F.P.C. report, raw data from other sources was gathered in order to develop a conservative estimate for the shut-in leases. Based upon history, significant gas production can be anticipated from shut-in leases. These

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[113] Energy Data, supra n. 98, at 30.

reserves of natural gas and oil are important in the planning of the nation's energy policy.

The lack of sufficiently reliable government data on projected reserves forces the Department of the Interior to rely upon gas and oil producer estimates. In the past estimates of reserves reported by oil and gas producers have proven to be unreliable. In the past, industry estimates of potential reserves have been at least 54% higher than those reported to the government.[114]

Without sufficient data on which to base a rational long-term energy policy, one must seriously question the sensibility and necessity of leasing 10 million acres of the O.C.S. The Subcommittee's contention is that it is irrational to think that one can meet the demand without knowing what one's supply is. To lease and drill additional O.C.S. areas at a point in time when other resources are readily available by and through these producible shut-ins is very unwise. Moreover, because the cost of extracting our natural resources is increasing, it is more efficient to compel oil producers to utilize those tracts which are presently under lease and to utilize the present available equipment and manpower in development of those tracts.

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[114] Id. at 33.

The Subcommittee found that the present leasing system was filled with numerous deficiencies that impaired the nation's ability to get its utmost out of its present energy supplies. Inadequate regulations and lax enforcement enabled oil producers' to obtain and control petroleum fields at bargain prices.

> The subcommittee finds that the Department of the Interior's resource evaluation record is dismal. The existence of single bids on large numbers of tracts indicates that the government may not have received fair market value for lease under the Department's responsibility. The subcommittee finds that the deficiencies of resource evaluation are inexcusable. It feels that the Department's failure to obtain more reliable data by the simple expediency of requiring each applicant to agree to turn over all exploratory data to the Department as a precondition to receipt of an exploratory permit. This subcommittee finds that proposed regulations to accomplish this result have been in existence within the Department of the Interior at least since March of 1971, over three and three-fourths years.
>
> The subcommittee finds that the Department of the Interior's proposed accelerated leasing schedule of 10 million acres leased in Calendar Year 1975 is of dubious quality. Thus, the subcommittee concludes that the selection of the 10 million acre goal is not related to the projected energy demands and anticipated supplies.[115]

Based upon the testimony, evidence and findings, the Subcommittee recommended that the Department of the Interior

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[115] *Id.* at 30.

(1) immediately implement procedures to improve its resource evaluation capabilities, including improvements in its data base; (2) immediately implement procedures to improve its bid evaluation process to ensure fair market value is received for all mineral leases, especially on leases on which only a single bid is received. In addition, the Subcommittee urged that the Department of the Interior establish a time limitation on how long a lease can remain undeveloped or shut-in. Also, the Subcommittee felt that the Department of Interior should require verification that sufficient numbers of drilling rigs, drill pipe supplies, production platforms, and skilled manpower are adequately developed and available to assure O.C.S. tract lease and development. The Subcommittee also recommended that the F.P.C. coordinate its efforts with the Department of the Interior regarding producible shut-in leases to prevent arbitrary reserve withholding and to establish natural gas pricing policies which do not encourage reserve withholding in anticipation of higher prices. We concur in this recommendation.

We urge regulatory procedures which establish definitive guidelines by which a U.S.G.S. regional engineer may grant a producible shut-in classification. Without specific guidelines, the possibility of misjudgment can compound the problem of abuse of the system by oil companies. We must not allow the oil companies to withhold oil and gas production in anticipation of higher prices.

2. Secondary and Tertiary Recovery

The testimony of Dr. Richard Perrine, Chairman of the Scientific Advisory Committee provides an excellent summary of the potential for enchanced recovery of existing wells. Scientific Advisory Committee Analysis, <u>infra</u>, p.101. We believe that this alternative to O.C.S. development has been inadequately considered by Department of the Interior. We refer, briefly, to information readily available regarding this alternative.

The production of more oil from existing, ostensibly purged, wells should also be considered. According to the Ford Foundation's <u>Time To Choose</u> secondary and tertiary recovery from existing tertiary wells could be a major source of oil over the next decade. Sustaining the rate of expansion of energy use will not require major inroads in presently undeveloped offshore provinces before 1985, with most of the expansion coming from secondary and tertiary recovery from existing fields, Alaska, and additional offshore developments in the Gulf of Mexico. The technology to extract additional oil from wells is currently available and improved methods are emerging constantly, making this a viable supplementary alternative.

F. National Naval Petroleum Reserves: The Elk Hills Example

At a time when America is striving to achieve energy independence, serious efforts must be made to open the nation's proven, existing major petroleum reserves to full domestic production. Reserves which must be considered as energy alternatives to expanded O.C.S. development include Petroleum Reserve IV in Alaska, and Elk Hills. Although Elk Hills is a much smaller reserve than "Pet IV" in Alaska, we know far more about it, and thus we will use it as an example of the petroleum reserve potential that must be discussed in the E.I.S.

The petroleum reserve at Elk Hills was originally created to provide a readily producible supply of petroleum for use in time of national emergency. The United States Department of the Interior managed the field until 1923. Management of the field since 1923 has been the responsibility of the Secretary of the Navy. The present size of Elk Hills Oil Field is about 46,000 acres and present ownership is about 80% United States Navy and 20% Standard Oil Company of California.

With the exception of limited usage during World War II, Elk Hills has never been fully tapped. Instead, approximately 1,000 wells have been drilled by the Navy into the shallow zone of the area confirming the huge amounts of oil available. Estimates of potential ranges between 3 and 5 billion barrels of oil.

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[116] California Energy Outlook, supra n. 93, at 3.

The reality is that there is no real justification for the Navy to continue to keep such product reserves. It is common knowledge that in times of military emergency, the military has first priority over all national energy supplies.

In a recent study,[117] consumption figures show that the Department of Defense (hereinafter referred to as D.O.D.) consumes only three of four percent of the total energy produced on the continental United States and Alaska[118] and that ". . . except for specialty fuels, the D.O.D. is an almost insignificant part of the market for gasoline, diesel fuel, and fuel oil."[119]

The D.O.D. consumes approximately 53.5 percent of all jet fuel produced in the United States. Jet fuel is produced by special contract.[120] If a military situation did arise, the curtailment of civilian flights would readily meet all additional jet fuel needs of the D.O.D.[121] Thus, Elk Hills Naval Reserve is not, in fact,

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[117] Fisher, George P., Desulfurization, First Draft, R & D Associates (May 30, 1973).

[118] Id. at 4.

[119] Id. at 4.

[120] California Energy Outlook, supra n. 93, at 3.

[121] Perrine, Dr. Richard L., Professor and Chairman of Environmental Science and Engineering, Letter to Jan Chatten-Brown, Deputy City Attorney, January 14, 1975 at 1.

necessary for national defense.

Another compelling reason to open Elk Hills is its ready availability. At the present time, Elk Hills is capable of producing 50,000 barrels a day; within two months the capacity could be increased to 160,000 barrels a day; 230,000 barrels a day could be produced in 18 months and within 3 years maximum production would be 350,000 barrels a day.[122]

By contrast the earliest oil production from the proposed Federal lease land in the Outer Continental Shelf will occur no sooner than the early to mid-1980's. Reliable projections predict that production of 300,000 barrels a day from the O.C.S. will not be realized until the mid-1980's -- that is, 7 to 12 years from now.

In terms of operational cost, it is economically more sound to open production at Elk Hills. To increase production capacity at Elk Hills may require an expenditure of as much as $250,000 for each additional well that must be drilled, as well as additional expenditures to upgrade the pumping and refining capacities currently located in the project area. On the other hand, increasing production from the O.C.S. area will require the development of major offshore oil drilling platforms and wells, the estimated cost of which may be as much as $30 million with each well drilled at a substantially greater cost then onshore wells.

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[122] California Energy Outlook, supra n. 93, at 3.

We believe that making the Elk Hills Oil Reserve available is a viable alternative to outer continental shelf leasing for meeting our short term energy demands. In terms of cost, accessibility and production time, the decision to open Elk Hills would be well supported.

In his recent State of the Union message, President Ford supported the proposal to open Elk Hills Naval Reserve. With a new change in leadership of the Armed Services Committee of the House (the congressional committee that has traditionally had jurisdiction over this issue), the possibility for favorable passage of legislation which would open Elk Hills is within sight.

G. O.C.S. Development Cannot be Undertaken Within the Proposed Time Frame

The draft E.I.S. does not address the pronounced problem of the ability of the oil industry to keep production abreast of the proposed increase in domestic production of crude oil due to shortages of drilling rigs, equipment and skilled manpower. The ability to develop the leases in the proposed time frame has great significance for an analysis of the feasibility of the Interior Department's decision to lease 10 million acres annually on the Outer Continental Shelf as a means of reaching domestic energy self sufficiency. Some doubt has been expressed as to the ability of the oil industry to achieve this seemingly desirable level of energy resource independence due to possible constraints in the supply of certain raw materials, equipment and manpower essential to the production and processing of crude oil.

This discussion is based on information obtained from two recent federal reports. The first was prepared for the Ad Hoc Committee on the Domestic and International Monetary Effect of Energy and Other National Recource Pricing of the House Banking and Currency Committee. It is entitled <u>The Accelerated Development of the Outer Continental Shelf: Its Problems and Costs</u>. The second is <u>The National Ocean Policy Studies Report on the Outer Continental Shelf Oil and Gas Development and the Coastal Zone</u>, prepared by the staff of the Senate Committee on Commerce. Both reports discuss the effects of

shortages of equipment and construction materials on the oil industry's future capability to develop the tracts. The reports indicate that, if shortages are found to exist at present, and are projected to continue into the near future, then substantial doubts must be raised as to the viability of the rationale behind an accelerated O.C.S. leasing program.

The Federal Energy Administration's Project Independence Report attempts to provide an in-depth evaluation and analysis of out domestic energy problem. According to this report, "Materials and equipment are fundamental to the development of energy resources. Current energy development is slowed by shortages of particular items and long lead times for certain categories of equipment. Although industry has traditionally responded in a time and manner commensurate with increased demand, there are certain capacity limitations that cannot be overcome in the short-run: drilling rigs ordered in 1974 cannot be delivered until the first quarter of 1977; oil company tubular goods are in tight supply, reducing a potential 171 Million feet that could have been drilled in 1974 to 160 million feet; manufacturers of walking drag lines are fully committed for deliveries through 1979." The major findings of this section of the report indicate that certain items have the potential of becoming significant constraints upon future O.C.S. development. These items include: fixed drilling platforms; mobile drilling platforms; oil company tabular goods; and steel and steel products.

The "technical paper" on acceleration of the Outer Continental Shelf leasing by the Department of the Interior concurs with the Project Independence Blueprint findings that material and equipment shortages, current and projected, have the potential of hampering the success of the accelerated leasing schedule. The "technical paper" sums up the overall situation with regard to the supply of certain materials and equipment in the following statement:

> "The availability of sufficient quantities of exploration and construction equipment is crucial to rapid O.C.S. development. Current shortages in drilling pipe and in onshore and offshore rigs may affect accelerated development of the O.C.S. if the situation does not improve. Production platforms and skilled labor are also in short supply."

According to Project Independence Blueprint, steel is the basic material for virtually all capital equipment in construction throughout the energy sector; heavy steel plate for pressure vessels and draglines, steel shapes for pumps and compressors, steel rail for transportation, and steel pipe and tubing are important in the use of steel within the energy sector. At present, short supplies of steel products such as pipes, tubing and casings are prevalent. These shortages surfaced as one of the consequences of the Economic Stabilization Program, during which time the steel industry cut back on production of low-profit items such as tubular goods. The Department of Interior's "technical paper" states:

> "The scarcity of drill pipe, tubing and casing has become critical in the past 8 months. Exxon expects to fall 20% short of its targets unless there is an improvement in supplies. Another major producer on the Gulf coast will be able to purchase only enough casing for 30 to 35% of this year's planned well."

As a result of this deficient supply of steel available in relation to demand, another serious shortage has developed with respect to production platforms. The components of such a platform, especially those composed of steel, are in short supply at present. The lead time required to manufacture a production platform is currently between 12 and 18 months. There is little possibility of increased production of these platforms in the near future because according to the "technical paper", "the utilization rate of current productive capacity is almost 100%".

The rotary drilling rig is the major piece of equipment used during the exploration and development of oil and gas fields, both onshore and offshore. The availability of these drilling rigs in relation to the projected requirements was found by Project Independence Blueprint to be one of the potential constraints that would have a negative impact on increasing domestic energy production. According to the Project Independence Task Force Report: "Higher petroleum prices have increased domestic drilling activity which, in turn, has increased the demand for drilling rigs. There is currently a short supply of rigs because long lead

times on raw materials and equipment are delaying their completion." This shortage can be directly attributed to the shortage of steel discussed in the preceding section and cannot be corrected until the steel industry is able to increase production and close the gap between the availability and requirements of steel products essential to oil and gas development. This finding, in view of the necessity of drilling rigs in exploration and development of any field, serves as a very strong argument in favor of reassessing the proposed accelerated O.C.S. leasing program. Without an adequate supply of drilling rigs, rapid development of even five million acres on O.C.S. would be impossible. This raises the question of what justification the Interior Department has for proposing the immediate sale of 10 million acres at this time, if the oil industry will be incapable of exploring and developing anywhere near that amount of acreage?

The availability of drilling platforms, both mobile and fixed, will be another potential constraint on the future expansion of domestic energy production. The F.E.A. Project Independence Report concludes:

> "The potential shortage of fixed and mobile drilling platforms is more acute than for any other material and equipment item. Even with optimistic assumptions or mobile platform production, and world fleet movement to U.S. waters, requirements under an accelerated development strategy exceed

projected availability by approximately 38%; the corresponding shortage for fixed platforms is 36%."

These projected deficiencies in platform availability are of great significance when analyzing the O.C.S. accelerated leasing strategy due to the essential role of these major pieces of equipment in any future O.C.S. oil field development. The report to the Committee on Banking and Currency has provided evidence that casts some doubt on optimism expressed by representatives of the oil and steel industries as to the future supply of steel and steel products. Basically, the potential problems are the availability of: 1) capital for capacity expansion, modernization and replacement; 2) energy; 3) raw materials; and 4) manpower. The report to the Committee on Banking and Currency does not share in the optimism expressed by oil and steel representatives. Rather, they conclude that current shortages in steel and steel products, and the threat of potential problems with capital availability and the supply of raw materials, raise definite questions as to the advisability of the federal government undertaking a program of accelerated leasing of O.C.S., such as that propounded by the Interior Department.

Another major problem facing oil companies is the critical shortage of skilled and professional manpower to design and operate increased production facilities. According to the National Ocean Policy Study, shortages of professional manpower are related to the uncertain leasing

policies of the government, which do not create incentives for students to major in petroleum and other relevant areas of engineering. Although the proposed O.C.S. development will create a demand for such professionals, there is at present a critical shortage which cannot be immediately filled. Oil companies apparently would not be ready to start exploration and production efficiently until the manpower is available. This shortage is but another reason to reevaluate the headlong rush to increase oil production on the Outer Continental Shelf.

H. Mitigation Measures Not Adequately Considered

Another deficiency of the draft E.I.S. is its failure to give adequate consideration to measures which would mitigate the potential adverse environmental effects of the proposed O.C.S. development. Mitigation measures not fully considered are: (1) immediate exploration of O.C.S. but delayed development and/or production; (2) priority in lease sales in areas farthest offshore; (3) camouflaging rigs; (4) subsea completions; and (5) commitment to more stringent drilling and production regulations. The relevance of each of these mitigation measures to the proposed O.C.S. development is discussed below.

a. Immediate Exploration But Delayed Development and/or Production

One mitigation measure is immediate exploration of the proposed lease zones but with no development, or, in the alternative, immediate development with well shut-ins. That is, potential oil reserves are located, but development and/or production do not occur until additional oil and gas are needed to satisfy estimated future energy demands.

The basis for this measure is that at the present time we may not need all of the oil and gas contained in offshore reservoirs. Restraining current development and/or production thereby conserves valuable oil and gas reserves

until some future time when our energy needs may be more urgent.

Immediate exploration with delayed development and/or production is a sensible mitigating alternative to immediate exploration, development and production. The draft E.I.S. fails to consider that alternative.

b. Priority in Lease Sales in Areas Farthest Offshore

Another mitigating measure is to give priority to lease sales in areas farthest offshore, thereby reducing at least temporarily the potential adverse effects upon highly valued coastlines. Production would move inland only when outer tracts containing sufficient quantities of oil are depleted.

Initial development of outer tracts has several advantages. According to the Bureau of Land Management, tracts recommended for the proposed Southern California lease sale extend 100 miles out to sea. These tracts would not be visible onshore, thus preserving aesthetic values. Also, deep water areas have proven to be far less sensitive to oil spills, while the distance from shore decreases the likelihood that oil spill containment efforts will successfully prevent beach contamination. The draft E.I.S. does not consider the mitigation measure of priority in lease sales in areas farthest offshore.

3. Camouflaging Rigs

Currently, oil companies are not required to camouflage offshore drilling platforms to reduce degradation of aesthetic values. Yet offshore platforms can be camouflaged to make derricks aesthetically more pleasing and even to reduce visibility to the onshore viewer. Camouflaging rigs is also technologically and economically feasible.

One device is thin milar plastic, aluminized on one side to create a mirror effect, which, when hung from the platform at an acute angle of less than 90 degrees, reflects only the ocean to an onshore viewer, thus disguising the platform entirely. Another method is the use of refractive devices to bend visible light so that persons viewing the horizon at water level see only the background and not the platform. Neither method would cause any navigational hazard.

Efforts to reduce adverse aesthetic impacts are not unimportant. Over 200,000 homes in Southern California have a view of the ocean. Many other persons come to the ocean for pleasure and solace. The draft E.I.S. does not consider camouflaging drilling rigs to mitigate interference with aesthetic pleasure.

4. Subsea Completions

Subsea production facilities represent a potential mitigation measure in that: (1) no drilling platforms would be visible, thereby preserving aesthetic values; and (2) no obstructions would occur on the surface, thus reducing the

danger to ship traffic and preserving recreational boating areas. The draft E.I.S. dismisses subsea completions because of greater economic costs and lack of accessibility in the event of blowouts, spills and other problems. Industry has not had extensive experience with subsea production facilities and thus the safety of such a method has not been demonstrated.

Several companies, however, have developed underwater production devices called subsea completion systems. According to the Western Oil & Gas Association (W.O.G.A.), there are currently six announced subsea production systems which are either being designed, constructed or field-tested in a marine environment. W.O.G.A. also states that within the past decade industry has made substantial progress toward subsea operations. Because of increased demand for such systems, a number are being developed and will be operational by 1980. More restrained development and production of offshore oil reservoirs would permit the utilization of subsea completion systems.

5. Commitment to More Stringent Drilling and Production Regulations

Another important mitigation measure is more stringent drilling and production regulations. Despite promulgation of O.C.S. orders designed to mitigate pollution and maximize platform safety, thousands of minor oil spills and five or six major spills of over 1,000 barrels have occurred since the

implementation of the new O.C.S. operating orders (Bureau of Land Management, Energy Alternatives and Their Related Environmental Impacts, 1973). The continued spillage suggests that the new O.C.S. orders are not sufficiently stringent or, alternatively, the orders are not adequately enforced. Due to inaccessibility, there are greater safety hazards associated with offshore drilling than for land operations. Special training of all offshore personnel to work with safety and anti-pollution devices is not only beneficial but essential. The Offshore Operations Committee, a joint effort of W.O.G.A. and the American Petroleum Institute, conduct classes which provide the following training: (1) knowledge of safety regulations of all applicable authorities; (2) specific instructions regarding operation of equipment and possible hazards; (3) orientation programs for personnel going offshore for the first time; (4) first-aid courses: (5) fire prevention and suppression technology; and (6) procedures and drills for general alarms which conform to United States Coast Guard rules and regulations. Strengthening existing O.C.S. regulations to include a mandatory training program of a similar nature would be an important mitigation measure.

Another mitigation measure would be stronger enforcement of O.C.S. regulations. Two recent studies found that U.S.G.S. did not enforce its orders to the fullest extent, but often issued only oral warnings about violators when

written notices or fines were appropriate. In view of the potential adverse effects upon the environment of a major oil spill, vigorous enforcement of O.C.S. orders is imperative. O.C.S. leasing should not proceed unless a commitment is made to better enforcement. The draft E.I.S. does not discuss that critical mitigating measure.

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[123] National Academy of Engineering Marine Board, O.C.S. Resource Development Safety: A Review of Technology & Regulation for the Systematic Manimization of Environmental Intrusion From Petroleum Products (Dec., 1972).

[124] Comptroller General, Improved Inspection & Regulation Could Reduce the Possibility of Oil Spills on the O.C.S., a report to the Conservation & Natural Resources Subcommittee, Committee on Goverment Operations, House of Representatives (June, 1973).

I. Failure to Consider Relative Environmental Effects

The relative environmental impact of O.C.S. drilling is not adequately addressed in the draft E.I.S. We recognize that the draft E.I.S. is not responsible for identifying and discussing all unique environments potentially affected by O.C.S. leasing. Yet lease sales are proceeding in specific areas without any knowledge as to what areas can best withstand the adverse environmental impact of O.C.S. development.

In our view, the type of reasoned, systematic decision-making mandated by N.E.P.A. requires a two-step approach on the matter of O.C.S. development. First, the necessity for, and consequences of, O.C.S. development must be analyzed. Second, if a decision is made that such a development is necessary, only then should a general environmental and resource analysis be made as to what areas of the O.C.S. are most appropriate for development.

We do not suggest that there can be drilling off Alaska, the Atlantic and the Gulf of Mexico, but not Southern California. We do suggest that an analysis of the relative environmental impacts of drilling various areas should be analyzed, and that no additional action in furtherance of drilling any area of the country should be taken until such an analysis is made. The Department of the Interior, on the other hand, has focused on particular areas for leasing and committed substantial resources to preparing for leasing without first answering the questions. Should there be leasing, and if so, where ? We had assumed that the program E.I.S. would make at least some attempt to do a relative environmental impact analysis.

1. O.C.S. Oil and Gas - An Environmental Assessment A Report to the President By the Council on Environmental Quality, April 1974

The President's Council on Environmental Quality prepared an analysis of the Atlantic coast and the Gulf of Alaska which was released in draft as a preliminary report in April, 1974. Essentially, the report attempted to compare the relative environmental impacts of several possible drilling sites. The study first focused on a number of possible drilling sites in areas considered by geologists to be particularly promising for oil and gas discovery. The analysis proceeded to examine the potential impact on the marine environment of developing these sites as well as the predictable onshore impacts of industrialization and growth which will result from offshore production. The study also assessed the present oil and gas production technology and the institutional and legal mechanisms for managing O.C.S. development.

The basic premise underlying the conlusions and recommendations of the report was that the benefits of potential oil and gas development must be balanced against the risks of environmental damage. When the balance is favorable, development should proceed with caution and with a commitment to minimize the damage. When the balance is unfavorable the Council believes that development should not move ahead until environmental risks can be lowered to an

acceptable level.

The report does not purport to be a complete analysis of all the factors that might be considered. Rather, it is a broad assessment which can serve as a model that could be followed for proper O.C.S. development.

Areas are singled out as potentially productive on the basis of their favorable geology. Generally, such areas are characterized by thick geologically young marine sediments. But judgments based on such indirect geophysical techniques can only roughly estimate quantities. Exploratory wells may be necessary to discover whether commercial quantities or oil and gas are present.

Putting aside the ultimate question of which areas should be put into production, the decision should be made with a perspective on future energy needs and the growth of alternative or supplemental sources of power such as coal, geothermal energy, oil and gas from coal and shale, nuclear, and solar energy.

The effect of natural phenomena upon O.C.S. development should be given careful consideration, including general weather conditions, severe storms, earthquakes, and tsunamis. Such information is critical to O.C.S. structural design and to assessment of site acceptability.

We recommend the report of the Council on

Environmental Quality as a possible model for the Department of the Interior in the production of further E.I.S.'s relating to expanded O.C.S. development. The C.E.Q. report is not, however, a perfect model. We also recommend the critique of the C.E.Q. report by the National Academy of Sciences contained in the appendix to the C.E.Q. report.[125]

2. <u>Factors Which Must be Considered in Determining Where to Lease</u>

As a specific example of factors which should be considered when the study of relative environmental impacts is prepared, we would like to draw attention here to the many varied and important environmental resources of the Southern California coast in order that due consideration and maximum protection be given to them.

The climate of the coastal plain of Ventura, Los Angeles and Orange Counties is one of the mildest in the United States, a fact which in part, is responsible for this area being the most densely populated in all of California. The high density of human population there places a heavy demand on environmental resources of the coastal region, and upon the resources of regions far beyond the coastal area. Moreover, geological structure, geographical location, and biological

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[125] Council on Environmental Quality, A Report to the President; O.C.S. Oil and Gas - An Environmental Assessment (April, 1974).

evaluation have combined to make the sea off Southern California one of the truly unique and productive areas of the world. A variety of habitats are present including estuaries, mud flats, sand beaches, bays, rocky shores, kelp beds, shelves, submarine canyons, basins, troughs, submarine sea mounts and islands. According to the report entitled "Southern California's Deteriorating Marine Environment", prepared by the Center for California Public Affairs, western continental shorelines are upwelling coasts, and thus, being shallow to a great distance offshore, very fertile with a high potential for productivity. As an example, about 50 percent of the fish taken from the sea each year are caught on upwelling coastlines; however, only one percent of the area of the ocean is described as upwelling; comparatively, therefore, upwelling coasts are roughly 1,000 times more productive than other 99.9 percent of the ocean's surface.

Significantly, B.L.M. expects <u>some</u> accidental spillage of oil through the drilling and production process. According to the publication "Energy Alternatives and Their Related Environmental Impacts" prepared by the B.L.M., small spills between a fraction of a barrel and fifty barrels probably occur on the order of 1,000 times per year in the Gulf of Mexico. It is difficult to determine the potential impact from chronic low level spillage, but Max Blumer in <u>Oil Pollution and Oil on the Seas</u> states: "We are rather ignorant about long term and low level effects of crude oil pollution. I fear that these may well be far more serious and long lasting than the more obvious short term effects." (p.103) Larger

spills, although infrequent, are an established fact and a direct result of O.C.S. leasing. According to the draft E.I.S., O.C.S. production in the Gulf of Mexico alone from 1964 through 1971 resulted in a total of 10 major oil spills of 42 thousand gallons or more of crude oil in each spill.

The draft E.I.S. states that degradation of water quality by routine operations will be slight and that brines added to sea water quickly diffuse into the water column. That assertion is refuted by the Bureau of Land Management's own publication Energy Alternatives and Their Related Environmental Impacts, which states on page 140 that the natural conditions of sea water will be altered and degraded in several ways during oil and gas operations. Debris and bilge will be released into waters from the many seismic vessels, crew boats, tugs, service and supply boats used throughout the operation. They also state that the production and discharge of formation waters (oil-field brines) is a potential source of pollution. Three properties of these formation waters which contribute to water quality degradation if released into the sea are: (1) the small amount of trained liquid hydrocarbons, (2) the high concentration of dissolved mineral salts, and (3) the absence of dissolved oxygen in formation waters.

The draft E.I.S. acknowledges on page 310 of the second volume that the incidence of spillage of formation waters and drilling muds must be considered routine, after treatment for entrained oil. Estimates were developed that 75 barrels of formation waters per well per day and 12,000 barrels of mud per year would be disposed under accelerated leasing. For the

expected production of oil under this acceleration, according to the E.I.S., 8,500 barrels of oil will be spilled per year through routine operation.

The E.I.S. states that the most severe impacts that can affect the organisms and marine coastal ecosystems are those resulting from spilled oil. A report made by the Southern California Association of Governments points out that these impacts will be magnified in the frontier areas of Southern California, because ecosystems here are already stressed by natural seeps of oil and, in the Santa Barbara Channel, by already existing oil drilling operations. In addition, Southern California coastal waters are already polluted from a number of onshore domestic and industrial sources. Therefore, any impacts from spilled oil would increase the severity of impact on an ecosystem which is already so overloaded that the additional impact of either a massive oil spill or continuous small spills at a sublethal level may be beyond the natural recuperative powers of our ecosystem.

Interference with boating and ship navigation will be a significant problem in the coastal waters of Southern California due to the great numbers of recreational and commercial boats and ships presently navigating through the areas which have been proposed for O.C.S. drilling. The E.I.S. admits that oil platforms will constitute an obvious interference with ship navigation but then concludes that this interference is easily avoided and not particularly bothersome. We fail to see how this conclusion can be made when, navigating at night, and especially in rough weather, fog, and heavy seas, collisions with oil platforms are almost

inevitable. The only alternative to this danger would be the imposition of strict boating and shipping fairways which would seriously detract from the quantity and quality of recreational activities.

In Southern California, 80 percent of the population live within 30 miles of the coastline. Thus, the beaches serve as an invaluable source of recreation. The draft E.I.S. feels that this interference with recreational activities merits but one page of discussion and finds that recreational curtailment is generally regarded by users as abusive. We feel that E.I.S. has drastically understated the importance of beaches as a recreational outlet. We consider California's beaches as one of its highest priorities for protection. An oil spill or a series of small accidental spills would directly affect shoreline activities such as sunbathing, swimming, diving, beachcombing, as well as scuba diving, boating, fishing, and water skiing. During warm months Southern California's beaches provide possibly the only relief from inland temperatures and heavy smog. Were its beaches to become fouled with oil, the repercussions would be enormous. This is a chilling thought when coupled with a statement from the publication, Energy Alternatives and their Related Environmental Impacts prepared by the B.L.M., that, "In any complex industrial operation involving heavy equipment, flammable materials, work at sea, and large numbers of employees, it is inevitable that accidents will occur." Were this to happen, the public benefit of added oil would be outweighed by the serious detriment of loss of use of our precious coastal resources.

Another significant yet briefly mentioned impact is the degradation of aesthetic values. The draft E.I.S. states that it is possible that some portions of platforms, drilling rigs and other structures and transportation facilities of the oil and gas industry will be visible to a shoreline viewer. We submit that it will be impossible to avoid the sight of platforms and traffic save for periods of storm or fog. The E.I.S. states that visual effect would be considered adverse by some persons while the Western Oil and Gas Report goes so far as to say that tourism might increase due to persons coming to see the rigs. The draft E.I.S. properly concludes that the obvious significance of such degradation is a reduction in the quality of living for those people who dislike the sight of oil rigs near pristine shores. _A fortiori_, the more highly used areas like Southern California will have more people disturbed by this factor.

One of the most serious risks associated with O.C.S. drilling in the Southern California area is seismic activity. In regard to the tracts proposed for leasing, according to a statement of Western Oil and Gas Association, the seismicity is a more significant factor for the coastal shelf because these regions are seismically related to onshore fault components. The draft E.I.S. only briefly discusses the potential dnager, noting that virtually all of the coastal areas lie within Zones 2 and 3, which pose the danger of moderate to major potential structural damage.

According to the Western Oil and Gas Association's Environmental Study, Areas A-1 and A-2, representing Santa Monica

Bay area and the San Pedro Bay area, are located adjacent to major faults. The San Pedro area has the greater seismic hazard because of the Newport-Inglewood fault. In fact, parts of this area, as projected for this assessment, are located near the epicenter of the Long Beach earthquake. The closer the structures are to this fault, the greater the risk of strong acceleration. According to the same study, area A-2 or Santa Monica has less risk than area A-1, but still may incur large accelerations. Although the Malibu fault has not been a source of major earthquakes recently, it is projected to have the capacity to generate large earthquakes. In addition, there are many subsidiary faults associated with it which are also active, especially to the west of the area. Moreover, all the faults have primarily thrust components, which produce relatively high acceleration or ground motion.

In addition to ground motion, there are other hazards resulting from seismic activity. The most important of these is fault rupture and displacement. Most of the faults in the Southern California area have a potential for fault rupture which may be due to small earthquakes on the fault or possible motion from a larger, more distant, earthquake.

Two other hazards associated with seismic action are liquefaction and tsunamis. Liquefaction is seismic-induced mobility in loose saturated sediments which can cause failure of the sediment on the sea floor. Seismic activity can generate sea waves or tsunamis. Although most tsunamis are from distant earthquakes, some local events, especially on the Santa Barbara Channel, have generated small waves. Due to this dangerous phenomena, drilling locations should be chosen with awareness of the possibility of earthquakes on or near a platform or oil pipeline.

There are desirability rankings in the E.I.S. for various proposed O.C.S. areas throughout the nation. Southern California generally places at number 4 or 5 depending on the ranking. There are no rankings of potential environmental impact. If there are areas of high environmental risks, then those areas should not be developed before areas of lesser risk are fully utilized -- even if they have less oil.

J. Degradation of Air Quality

Increase of offshore activity necessarily leads to increased onshore development because of the necessity of support facilities. An onshore activity with significant effects on air quality is the construction and expansion of oil refineries. California presently has 34 refineries with an estimated crude oil capacity of 1,852,000 barrels/day.[126] 15 refineries are located in the South Coast Region with a total capacity of 1,012,000 barrels/day. Ten of these refineries are located in coastal regions.[127]

Increased demand for petroleum products, anticipated imports from the Alaskan North Slope and possible O.C.S. leasing will increase pressure to construct new refineries along the West coast. Economic considerations including major capital requirements for equipment, construction labor and material cost, land value and accessible markets, enhance the probability that new refineries will be located in the vicinity of large metropolitan markets.[128] In fact, 12 refinery projects have been proposed for construction in California.[129]

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126 Calif. Energy Outlook, supra n. 93, at 3.

127 South Coast Regional Commission, Energy, California Coastal Zone Conservation Commission (October 28, 1974), at 175. (hereinafter cited as Calif. Coastal Zone Report)

128 Radian Corporation, Final Report, A Program to Investigate Various Factors in Refinery Siting, submitted to Council on Environmental Quality and Environmental Protection Agency (February 15, 1974) at 54. (hereinafter cited as Radian Report)

129 Calif. Coastal Zone Report, supra n. 127 at 117.

Refineries are considered by E.P.A. to be a stationary source; that is, a source which emits a number of effluents to the ambient air. Refineries emit 5 major pollutants; sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide and hydrocarbons.[130] Construction of refineries in Southern California will have a significant adverse impact on present air quality. Increased onshore activities such as refinery construction, production, increased manpower, vehicular traffic, etc., are major factors in evaluating the environmental impact of O.C.S. development. Such threats to air quality are not adequately discussed in the draft E.I.S. Four pages are devoted to a superficial presentation of air quality in Northern, Central and Southern California. No mention is made of related onshore development and anticipated degradation of air quality in nearby areas.[131]

A recent study by the Radian Corporation[132] analyzed the environmental ramifications of refinery construction and production. A large new refinery with a production capacity of 200,000 barrels/day was selected as a model for study. A typical refinery consists of a combination of standardized unit processes. Each unit process contains equipment to perform a refining operation on whole crude, or a fraction of the crude. These refining operations include separation by fractionation, conversion by catalytic

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[130] Radian Report, supra n. 121, at viii.

[131] The Draft E.I.S., pp. 104-108.

[132] Radian Report, supra n. 121, at i.

reaction to more desirable or higher quality products, product treating processes, and auxiliary operations for such purposes as by-product control, storage and others. Ambient air emission estimates were prepared for each of the unit processes.[133]

Sulfur dioxide is emitted from refineries as a result of burning fuels containing sulfur of both gaseous and liquid fuels. If the sulfur content is minimized, the resulting sulfur dioxide is minimized. Modern control technology does exist which can control emissions. Gaseous fuels can be treated with an absorbent. Sulfur can be removed from liquid fuels by hydrodesulfurization treatment.[134]

Nitrogen dioxides are a component of flue gases which are released during the furnace and power plant boiler stages. Generally, nitrogen dioxides can be controlled by combustion control design features such as two-stage combustion or off-stoichiometric firing. One exception is the ethylene plant. High flame temperatures are required by this process, precluding combustion modification. Uncontrolled emissions of nitrogen dioxides are a result.[135]

The "cat" cracker is a significant potential source of particulate matter and carbon monoxide. The catalytic cracking process converts heavy distillant oils (typical boiling range of

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[133] Id. at iii An analysis of waste water effluents was also included but is not discussed in this presentation.

[134] Id. at 193.

[135] Id. at 194.

650° to 900° F.) into petroleum fractions of lower boiling range and of correspondingly lower molecular weight. If the refinery installed the best available control devices, particulate matter and carbon monoxide emissions could be contained within federal standards.[136]

However, the Radian study discovered that even if the best control devices and good maintenance procedures were followed, hydrocarbon emissions would be in excess of federal standards by a factor of 20 to 40.[137] Hydrocarbon leaks were found throughout the refinery and storage areas and especially around pumps, valve glands, and flange areas.[138]

A violation of the hydrocarbon standard by itself is not reported to constitute a public health hazard, but photochemicals formed by hydrocarbons do constitute a hazard to the public's health.[139] "The major air pollution problem in California is photochemical air pollution (smog) which is caused by atmospheric reactions of hydrocarbons and oxides of nitrogen in sunlight."[140]

The Radian Study reports that the estimated impact of a 200,000 barrels/day refinery upon ambient air quality can be significant. Hydrocarbon emissions will cause the refinery to

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136 Id. at 194.

137 Radian Corporation, Technical Memorandum: Some Environmental Considerations in the Petroleum Refining Industry (March 13, 1974), at 22. (Hereinafter cited as Radian Corporation Study.

138 Radian Report, supra n. 121, at 195.

139 Radian Corporation Study, supra n. 130, at 22.

140 Air Resources Board, Air Pollution in California: Annual Report 1973 (January, 1974) at 6. (Hereinafter cited as Air Resources Report.

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exceed the primary air quality standard.[141] Other emissions will not exceed federal standards _if_ refineries install the best available control technology.[142]

The fact that other emissions may not exceed federal standards does not mean that refineries are not major pollution contributors. The Study cautions readers to consider the impact of the refinery on the surrounding air quality and not the surrounding environment on the refinery.

> "If a sufficient quantity of these pollutants (sulfur dioxide, carbon monoxide, particulate matter, nitrogen dioxide) is emitted by other sources in the vicinity of the refinery, then federal ambient air quality standards will be exceeded. That is, the refinery could contribute to the violation of federal ambient air quality standards even though the emissions from the refinery do not violate the standards in and of themselves."[143] (emphasis added)

This finding is particularly important in considering the environmental impact of additional refineries in Southern California. The South Coast Air Basin now produces 38% of the total tonnage of air pollutants in California.[144] Large quantities of man-made pollutants are emitted into the atmosphere each day. Based on 1972 studies, the following table shows the emissions of major pollutants on a daily basis in Southern California as

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141 _Radian Corporation Study_, _supra_ n. 130, at 22.

142 _Id_. at 22.

143 _Id_. at 22.

144 _Air Resources Report_, _supra_ n. 133, at 6.

well as in the entire state:[145]

Major Pollutant	Southern California	State of California*
	(tons per day)	
Nitrogen oxides	1,444	3,800
Hydrocarbons	2,242	5,900
Carbon monoxide	9,120	24,000
Particulate matter	722	1,900
Sulfur dioxide	376	990

A consulting firm, K.V.B. Engineering, Inc., recently reported its findings on South Coastal Air basin emissions.[146] The K.V.B. study estimates that stationary sources (including refineries) contributed 28% of the total emissions during 1972.[147] Furthermore, refineries were estimated to contribute more than 100 tons/day of nitrogen oxide emissions found in the Los Angeles Basin.[148]

There is little doubt that the quality of air in Southern California is far from reaching primary ambient air quality standards. Though some reduction of hydrocarbons and carbon monoxide emissions have been achieved, this trend is forecast to be re-

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145 *Id.* at 13.

146 *Los Angeles Times*, January 19, 1975 at Part II, page 1.

147 *Id.* at 1.

148 *Id.* at 3.

* A computation of 38% was calculated against each of the reported figures.

versed as a result of stationary sources switching from natural gas to oil for fuel. K.V.B. indicates that nitrogen dioxide emissions will increase by 15% by 1980.[149]

The gloomy forecast does not take into account a possible increase in crude oil refineries. Yet, if O.C.S. leasing is approved, the demand for refinery construction will result in expanded refinery facilities. Such activity will undoubtedly result in further degradation of present air quality and pose an undue burden upon local residents who must work and live in a polluted environment.[150]

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149 Id. at 3.

150 Air Resources Report, supra n. 133, at 7.

K. Insufficint Data for Environmental Analysis

The E.I.S. is replete with statements that data is not available regarding marine and coastal resources, as well as the potential impact of O.C.S. development on these resources. As indicated previously, we believe that the Department of the Interior has an affirmative obligation to develop the data necessary for evaluation of the full impact of O.C.S. development.

Below is a list of specific areas where the E.I.S. admits a lack of adequate data. In those instances where we have discovered literature sources of data already available, we have so indicated. Where we do not indicate alternative literature sources, it does not mean that such sources are not available, but only that with our limited time and resources we did not discover them.

1. "There are large gaps in the scientific information that cause problems in analyzing and predicting the impacts of O.C.S. Oil and Gas Development." P. 128 of draft E.I.S.

2. "Though all predictions imply uncertainty, it is rational to assume a continuation of the secular growth in G.N.P. and, hence, a corresponding rise in aggregate energy consumption." P. 145.

3. "It is important to point out that predictions of effects at the community, or even population, level cannot be determined from existing literature....Quantifiable comparisons are not possible in these areas due to a scarcity of quantification of population levels and dynamics preceding the spills." P. 157. Data available in Oil Pollution and the Public Interest, A Study of the Santa Barbara Oil Spill, by A.E. Nash (1972)

4. "Consequently we cannot predict in a truly quantitive manner what the impacts of offshore drilling will be in newly opened areas." P. 159. Data available in Restoration Cost Estimate of Coastal Areas Contaminated by Material Related to 1965 Santa Barbara Spill, prepared for California Attorney General, by U.R.S. Research Company.

5. "It is difficult to predict how pipeline burials, access channels necessary for construction equipment, and dredge spoil banks affect communities." P. 160. Data available in The Santa Barbara Oil Spill in Prospective, by N. Nicholson of California Cooperative Oceanic Fish Investigation Report (1972).

6. "It is difficult to predict whether new refineries will result from the proposed increase in acreage leased." P. 161. Data available in California Energy Outlook, 1974 to 1975, prepared by The California Energy Planning Council; The Accelerated Development of the O.C.S.: Its Problems and Costs, Report for House Committee on Banking and Currency (1974).

7. "The natural (chemical, physical, and bacteriological) degradation of crude oil is a complex and not well understood process." P. 162. Data available in Southern California's Deteriorating Marine Environment, R. C. Fay for Center of California Public Affairs (1972).

8. "Little information has been found concerning the effect of crude oil on the zooplankton." P. 165. Data available in Oil Spills and the Marine Environment, by Boesch, Hershner, and Melgram (1972).

9. "Chronic pollution from offshore production sights represents an unknown factor." P. 168. Data available in Southern California's Deteriorating Marine Environment, supra.

10. "We believe that the plankton of populations in the various geographic areas will be able to absorb the impact of a major oil spill and recover fairly rapidly. This is based partly on the lack of evidence that plankton populations are catastrophically impaired by oil spills."

P. 169. Data available in Santa Barbara Oil Spill: Short Term Analysis of Macro-Plankton and Fish. A. W. Ebeling for Environmental Protection Agency 1971.

11. "No information has been found on the effect of spilled oil on numbers of the plankton other than fish." P. 175

12. "The effects of the sublethal concentrations of oil on salmon migrations are unknown but potential for harm is clear." P. 174

13. "Of more importance is the effect on marine life due to chronic low level pollution by different substances including oil. This problem remains an unanswered question." P. 186. Data available in Environmental Assessment Study of Proposed O.C.S. Leases, by Dames and Moore for Western Oil and Gas Association, Volume 3.

14. "Although we have no conclusive evidence, it is our opinion that a major oil spill would effect sport fishing adversely." P. 217

15. "It is impossible to quantify the possible impact of an unpredictable event such as a major oil spill on beached and shoreline recreation."

P. 256. Data available in Physical Assessment and Clean-up - Restoration Cost Estimate of Coastal Areas Contaminated by Material Related to 1969 Santa Barbara Spill, prepared for California Attorney General by U.R.S. Research Company.

16. "The impact of exhaust emissions is unknown, but considering the small total horsepower requirements it is thought to be small." P. 260. Data available in A Program to Investigate the Various Factors and Refineries Siting, by Radian Corporation, Texas.

17. "Water quality could be further degraded as the result of accidental oil spills, but the degree of degradation is impossible to predict." P. 264. Data available in Hearings before National Ocean Policy Study: Oil and Gas Development and Coastal Zone Management Serial No. 93-99.

18. "It is impossible to quantify the effects of this proposed program, or even the present program, on the organisms themselves (Commercial fish and shell fish)." P. 274. Data available in Santa Barbara Oil Spill: Short Term Analysis of Macro-Plankton and Fish, supra.

19. "The additional stress which the ecosystem can absorb is limited, but at present, the bounds of these limitations are not known." P. 318. Data available in Southern California's Deteriorating Marine Environment, R. C. Fay for California Center for Public Affairs.

Although the Department of the Interior contends that baseline data is needed only to monitor O.C.S production, we believe that a certain basic knowledge of our resources is essential if we are to have a useful analysis of the impact of oil and gas production. In additon to the analysis provided by our own Scientific Advisory Committee, presented infra, we wish to set forth the assessment of current information developed by the Southern California Academy of Sciences, an organization under contract to B.L.M. for developing scientific data.

In late 1974 B.L.M. asked the Southern California Academy of Sciences to assemble scientists with expertise in the fields of chemical, geological, biological and physical oceanography in order to evaluate the need for baseline data on the

Southern California marine environment. A conference was scheduled to propose recommendations to B.L.M. for a meaningful and scientifically adequate baseline study. Based upon said data B.L.M. would then ask the Southern California Academy of Sciences to make findings as to the long term environmental effects of off-shore drilling on marine life.

Originally B.L.M. indicated that it wished to fund a 30 day study in order to gather pertinent data. However, the results of the conference indicate that a minimal study period for some disciplines (physical, geological, and chemical oceanography) is one year. Three to five years is considered essential by marine biologists in order to collect sufficient data on invertebrates and vertebrate species. The disparity in time estimated may be attributed to the scientists' evaluation of the present state of knowledge. At the 3 day conference held December 5,6,7, 1974, scientists continually expressed their concern with the lack of sufficient data with which to make a scientifically valid estimate of the effects of offshore drilling on marine habitats.

The depth and breadth of the proposed studies indicate the dearth of information about the Southern California Outer Continental Shelf that presently exists. Knowledge of the O.C.S. is characterized as being sparse and synoptic; that is, it is not uncommon to find intermittent scientific studies with little or no connection to each other. As a result, the scientific community does not have information which has been synthesized and

evaluated over an established period of time to yield cohesive and reliable data.

For instance, physical oceanographers indicate that little is known about subsurface movements. Such knowledge is essential because it relates to vertical and horizontal dispersions of pollutants. Little data has been accumulated on the effects of surface winds on ocean current and flow. Such information is basic to the understanding and prediction of dispersion of pollutants and the effects of oil spills on marine life.

Marine geologists acknowledge that there are extensive information voids as to seismic safety and the ramifications of offshore drilling. Basic information, such as bottom samples, sea force stability, and geological composition of the O.C.S.,is insufficient to answer such essential questions as: What are the engineering and physical properties of the outer continental shelf and proposed lease land? Do these properties constitute a hazard to potential oil drilling? To what extent is the sea floor modified by depositions and sedimentations?

Marine biologists urge extensive habitat studies which would provide data as to the variety of flora and animal life present along the Southern California O.C.S. To this date, research has not been conducted to determine tolerance and resistance levels of dominant organisms or groups of organisms and major habitats, to the presence of relevant levels of oil, heavy metals or other substances likely to enter the sea as a result of oil and gas development.

Chemical oceanographers strongly recommended an extensive study of the chemical ramifications of offshore drilling. Basic information regarding the total amount of hydrocarbons should be ascertained for indicator species in the pelagic and the benthic fauna and flora as well as for the suspended particulate matter and sediments. Specific compounds should be identified, monitored and measured depending on the nature of the resource being developed. Determination of trace metals in sea water and sediments should be investigated, particularly barium, mercury, molybdenum, nickel and vanadium.

The hesitancy of the Southern California Academy of Sciences to make any evaluations as to the ecological effects of offshore drilling until extensive studies have been conducted support the conclusion that the scientific community presently lacks sufficient and reliable data on which to base a critical analysis.

In order to illustrate the extensive proposed recommendations of the Southern California Academy of Sciences, the following is a summary of the recommendations of each discipline as it was presented to the Department of Interior.

1. Geological Oceanography

Seismic activity studies are crucial for safe drilling. Little knowledge appears to be available about Southern California's marine faults though we do know this is a very active area. Recently, the United States Geological Survey (U.S.G.S.)

returned from one of its first exploratory trips in the Cortes Bank (which is located in the proposed federal lease land). During this exploration trip, it was able to obtain geologic samples which would assist in determining surface sediments and sediment distribution. However, the results of this report will not be available until early Spring 1975. Scientists from the Geological Oceanography Division suggest that a number of various studies be conducted in order to provide vital and necessary information.

Scientists suggest increasing the present seismic monitoring system in the continental borderland. This increase should include the placing of bottom seismometers on selected banks, in particular the Cortes Bank. Also, to supplement seismic records, high resolution profiling, seismic retraction, gravity and magnetics should also be conducted.

Various core sample studies should be conducted in order to determine the stratographic composition of the continental borderland. Box core samples with printed photographs of bottom conditions are preferable. Gravity cores should be used where box cores are not feasible and where the engineering properties of sediments at moderate depths are needed.

Three hundred meter holes should be drilled where deemed necessary to detect evidence of instability. Holes of greater depths than 300 meters would require the U.S.G.S. to file an environment impact statement with E.P.A.

At least one deep basin should be drilled and cored

in order to compile as complete a stratographic record as possible. This record will provide concepts on the rate of deformation, tectonic activity, sediment influx, biotic production and bottom conditions, including base information.

A broad-based widely-spaced (20 kilometers) geophysical survey should cover the continental borderline for a preliminary survey. The completion of this survey would probably fill in the gaps in existing data. This general work at the surface at about 4 knots and 10 160 KJ will incorporate a 3.5 KHz profiler, side-scan sonar sniffer magnitometer and gravimeter.

A detailed closely-spaced 5 km geophysical survey would cover selected target areas where potential resources are thought to be, and platforms and pipeline right of ways are to be investigated. The deep tow package detail work (in deep water) at about 1/2 knot will incorporate a 3.5 KHz profiler, side-scan sonar, television monitor, bottom photography and sniffer. High resolution profiling should be done to determine hydrocarbon occurrences.

Transmissometer studies and suspended sediment studies should be done to determine the suspended sediment displaced and despositional patterns.

The following questions ask for information considered essential to the assessment of environmental hazards of offshore drilling. A large-scale base line data collection and monitoring program is recommended.

1. Does sea floor instability (seismic, slumping,

liquifaction) pose a potential hazard?

a. What are the physical and engineering properties of the seabed material (grain size, degree of consolidation, sheer strength, clay minerals, etc.)? In order to make such a determination, bottom sediment sampling programs including orintated box core and gravity cores (grab samples to be minimized), detailed age dating techniques, physical dating techniques, should be emphasized. Bottom photography should also be conducted.

b. Do these properties constitute a hazard? To answer this question the following studies should be conducted: a bottom sediment sampling program,including orintated box core and gravity cores, detailed age dating techniques and physical dating techniques, should be emphasized over paleontology and bottom photography.

c. Is there evidence of instability, e.g., slumping at present? To make this determination, one must conduct bottom sediment sampling programs, core hole programs (300 meter drilled holes), bottom photography, high resolution reflection profiling (3.5 KHz), detailed age dating techniques, physical dating techniques, seismicity and

side-scanning sonar.

d. What are the physical and engineering properties of the uppermost rocks beneath the unconsolidated sediment of the seabed, cementation, degree of induration, extent of fracturing, grain size, sheer strength and geologic age? This would involve conducting core hole sampling tests, bottom sediment sampling programs and age dating technique programs.

e. Has teutonic uplift or subsidence contributed to potential instability (high slope angles, evidence of recent uplift, and active fault traces)? Again, the following tests should resolve this particular question: high resolution reflection, profiling, reflection seismic test (air gun, sparker, etc., multichannel digital processed seismic data highly desirable), and core hole programs (300 meter drill holes).

f. How common and of what magnitude are earthquakes in this area? This involves the issue of seismicity.

g. Are overpressurized gases likely to occur? Again, in answering this question we must take into consideration the following tests:

hydrocarbon occurrences; location, identification and quantification using high-resolution profiling, side-scanning sonar, sniffer (continuous water sampling-gas chromatographic analysis), and bottom sediment sampling analysis seismic amplitude data, "bright spot", reflection seismic tests, high resolution reflection profiling.

2. To what extent is active faulting likely to be a hazard to offshore development?

   a. What is the distribution of faults in this area? Here reflection seismic tests and high resolution reflection profiling would provide relevant data.

   b. How recently have there been displacement on faults, dating and rates of displacement, etc.? Core tests and the age dating techniques including physical dating techniques will be relevant here.

   c. What is the seismic history of the area? Again, this goes to the issue of seismicity.

   d. What is its present seismicity? Additional stations are needed on Santa Barbara Island and Santa Catalina Island.

   e. What are the predictions of seismicity and

seismic risk? In order to answer this question the following tests must be conducted: seismicity, reflection seismic tests, high resolution reflection profiling, core hole programs, detailed age dating techniques and physical dating techniques.

3. To what extent and degree is the seafloor modified by erosion and deposition?

   a. What are the unconsolidated sediments (grain size, current indicators, (e.g. ripples, etc.,))and precise dating of recent sediments? Here bottom sediment sampling programs, including orintated box core and gravity holes, high resolution reflection profiling, detailed age dating techniques, current meter stations on and near bottom, long term measurements over minimum 14-day periods, bottom photography, seismicity, and side-scanning sonar.

   b. What are the external stresses exerted on sediments, including distribution efficacy? bottom currents? turbidity flow potential? waves? internal waves? tsunami action? Here current meter stations on and near bottom, and long-term measurement of current over

minimum 14-day periods will be necessary.

4. Are potential contaminants present? If so, their identification, release, dispersal, and areas of accumulation must be identified.

   a. What is the source and distribution of any recognized toxic trace elements? Use of bottom sediment sampling program for hydrocarbon occurrences, and location, identification and quantification using high-resolution profiling are necessary tests.

   b. What is the source and distribution of hydrocarbons, gas and oil seeps, shallow currents, etc.? Studies involving hydrocarbon occurrences, and location, identification and quantification using high-resolution profiling, side-scanning sonar, and sniffers would yield relevant data.

   c. What is the suspended sediment dispersal and dispositional patterns? Here tests using the transmissometer studies and suspended sediment studies (using water column data required in conjunction with the study) are necessary.

   d. What is the recent dispositional history of sediments in this area? Detailed age dating

techniques, bottom sediment sampling programs and high resolution reflection profiling would be of assistance.

e. Have the activities of man already significantly altered the natural environment (toxic metals, effluent, sediment distribution, etc.)?

2. Biological Oceanography-Invertebrates

The proposed study includes the following subjects:

(a) Habitat Surveys

The proposed lease sites are all located on ridges; thus general habitat types are likely to be similar and detailed work should begin on the least known areas such as:

(1) the outer most areas,

(2) the northern channel island area,

(3) the Santa Barbara Island and Santa Catalina Island areas, and

(4) two in-shore areas.

A broad general survey of the region, including satellite and/or aerial photography using remote sensing techniques, or apparatus such as "deep-tow" (a package towed by a ship and including a side-looking sonar magnetometer, television, and cameras). This survey should

provide a fairly detailed picture of the variety and distribution of major sea bottom types and habitats.

b. <u>Studies of Organismic Diversity, Distribution, and Abundance</u>.

Four major groupings of habitats need study in or near each of the potential lease sites:

(1) intertidal
(2) shallow subtidal
(3) benthic
(4) pelagic (at all depths)

Surveys need to be made in each major habitat. Such a survey should include the variety of plants and animals present and the spatial and temporal distribution of the most significant of these organisms. Significance should be determined on the basis of numbers, biomasses, positions, as well as food chain and direct economic value. A determination should also be made as to the relative abundance of these significant organisms.

The purpose for conducting such surveys is to determine the present state of animal and floral life in these general and major habitats. The present state of knowledge is very sparse. It is of vital importance to evaluate the general habitats in question.

The area south of Point Conception serves as a major

biotic region for the Pacific Ocean; its coastal line is complex and varied, thus creating numerous types of habitats attracting different types of animal and plant life. The region south of Point Conception to the Gulf of Mexico also acts as a transition region for many varied species because of its temporal variations. Numerous subcultures exist at the bottom of ridges and valleys which are supported by the various and diverse flora. Thus the area which is included in the proposed federal lease land serves as a major biotic area in relation to the food chain and production of invertebrate species.

(c) Studies of Ecological Dynamics

Laboratory studies are needed to develop understanding of food chains in different habitats and to determine tolerance and resistance of the dominant groups of organisms in the major habitats to the presence of relevant levels of oil components, heavy metals, or other substances likely to enter the sea as a result of oil and resource development.

Laboratory studies must be conducted in order to determine the effects of such substances on the dominant organisms in relationship to rates of growth, longevity, fecundity, nutrition, and pathology. Studies should also be conducted in order to determine the effects on other organisms in the food webs of feeding upon organisms containing high body-burns of importance substances, such as hydrocarbons.

(d) Time Frame For Completion Of A Study

A five year study is needed according to the scientific community for an adequate baseline study. The time frame includes start of time, three full annual cycles, each cycle including quarterly replicated analysis of floral and faunal surveys as described. It also includes data reduction, calculations, annual and final (published) report. The time frame does not include the continuing monitoring program which must follow this initial program to keep track of after-effects of oil developments.

The above described study is a minimal study which would include all of the components needed for a scientifically adequate, accurate, and reliable set of conclusions. It would provide a reasonable basis for predictive statements concerning possible effects of oil and resource development. It would also provide a sound foundation for assessment of the actual effects of whatever oil and resource development in fact takes place. Anything significantly less complete than this study will not constitute a scientifically adequate program.

3. Biological Oceanography-Vertebrates

The vertebrate species is one of the most sensitive to visible measures of contaminants in chlorinated water. In order to determine how a potential catastrophe such as an oil leak would effect marine life, more data must be gathered on the present numbers of various vertebrate species in Southern

California.

Replicated efforts are needed as all features that should be studied are in some degree of continual flux. Over a minimum 3-5 year study, however, a great deal of information can be obtained by annual cyclic and quarterly studies. Data gathered prior to the base-line studies should be incorporated in order to determine historical trends. Schedules should be arranged to take optimum advantage of breeding period, especially for birds and pinnipeds.

(a) Ship Operations

Two rather different sorts of ship operations are needed. First, ground truth (or "water truth") ship activity will be necessary in order to obtain data regarding (a) species identification from the air, (b) siting frequency of bird flocks or marine mammal schools, (c) number of animals reported and (d) correlation with marked animals obtained. The second ship operation will involve the capture, tagging, stomach analysis and tracking of animals. The ship will catch, lavage (obtain stomach samples of food and parasite analysis) by non-harmful means, freeze-brand, attach dorsal fin rototags and release animals concerned.

Considerable reservoirs of skillful and interested lay observers exist in Southern California. While for marine mammals highly trained professionals are recommended (because security of identifications is often difficult for many species),

groups might be invited to submit plans for work on certain species. For example, lay persons might describe the passage of certain migratory species such as the grey whale, the hump-back whale and the killer whale. Similar contributions for the bird program might come from organizations such as the Audubon Society.

(b) Marine Mammals

A survey must be conducted in order to determine the abundance and distribution of marine mammals. A once-monthly base line transect is needed using an aircraft and a strut or belly-mounted aerial camera assemblage. Haul-out and rookery grounds must also be overflown and photographed regularly. Most cetaceans and pinnipeds should be identified by species. Data gathered should be broken down as to school, locality, shape (feeding or traveling aggregation), resting or moving group, time of day and species.

Species of special importance will be chosen to be equipped with dorsal fin or harness radio tags for tracking by boat and air. There are four various types of visual tags. First, the plastic dorsal fin rototag may be attached to porpoises and whales. Secondly, the freeze bands may be attached to marine mammals without any harm to the animal. The last two types are spaghetti tag and laser-branding.

A survey must also be done of beached animals. The number of beached cetaceans and pinnipeds has

proven to be an indication of the health of a population. A monthly survey of selected searches of mainland and island shoreline is essential to determine the "normal" number of animals washed ashore. Causes of death and parasitic loads can be approached by sampling such dead animals and is recommended.

(c) Birds

Surveys of abundance and distribution should be made in conjunction with the marine mammal surveys using aerial censusing. Breeding colonies must also be overflown and photographed regularly. Birds may be identified to species, more often to genus and family. Data should be broken down into flock size, locality, time of day and species composition.

A key element in maintaining surveys of vertebrates is the measure of reproductive success in representative colonies several times within a breeding season. This is necessary in order to determine the number of young raised per pair and, if reproductive failure is found, to determine at what stage it occurs. Related to this effort, measures of hatching failure, chick mortality, and residues of DDE, PCB and petroleum hydrocarbons should be obtained.

4. Chemical Oceanography

Geographically, it is necessary that the study area extend beyond the proposed Federal lease land. The minimum

area to be studied should extend throughout the Southern California bight. (The bight extends from Point Conception in the north to just south of the United States-Mexico boundary.) The following is a list of specific recommendations that must be followed in order to provide sufficient data to predict the ecological effects of offshore drilling on marine habitats:

1. The total amount of hydrocarbons should be ascertained for indicator species in the pelagic and benthic fauna and flora, as well as in the suspended particulate matter and sediments.

2. Specific compounds should be identified, measured and monitored, depending upon the nature of the resource being developed.

3. Interfaces should be investigated, including sediment/water and water/air, including the dissipation and degradation of specific compounds.

4. Isotope methods should be utilized to determine the ratio of hydrocarbons to distinguish biogenic gases.

5. Analysis of samples to be undertaken on a quarterly basis.

6. Determination of base metals in seawater and sediments should be investigated, particularly barium, mercury, molybdenum, nickel and vanadium.

7. Determination and measurement of trace metals in pure water should be investigated, mobilization and precipitation of metals into the sediment should be studied.

8. All sediment analysis of trace metals must be

intercalibrated.

9. Slow-entry and/or clear-vented box coring techniques are recommended for sampling the surface sediment. Commonly used gravity, box, and piston coring techniques are not recommended.

10. All trace metal samples must be obtained and determined from undisturbed sediments, and from water column particulates in basin and slope regions adjacent to lease sites and on the bank lease sites as well.

11. Trace metal content of selected fauna and flora of both the benthic and pelagic realms should be determined.

12. Radionucleides should be measured in coastal waters, specifically those of known input sources.

13. Radionucleides in sediments should be analyzed to determine rate of sediment deposition and whether surface sediments have been disturbed.

14. Parent-daughter pairs of radionucleides in particulate matter should be examined for disequilibria values to determine particulate flux and pathways.

15. A single sampling effort for trace elements and radionucleides will be sufficient for sediment and pore water analysis.

16. Measurement of stable isotope ratios, carbon and nitrogen should be performed for particulate organic matter in both the water column and sediments.

17. The isotopic composition of the local offshore oil sources should be measured.

18. Sediment samples should be collected twice, and in locations that will allow isotopic variations between major topographic features to be defined.

19. Hydrographic parameters which need to be studied in the water column are temperature, salinity, oxygen, nitrates, nitrites, phosphates, silicates, ammonium, alkalinity, total carbon dioxide and excess Rn_{222}.

20. The hydrographic parameters which need to be studied in interstitial waters are nutrients (NO_3, NO_2, NH_4, PO_4, SiO_2, alkalinity, total carbon dioxide, sulfate, sulfide and gas analyses).

21. The hydrographic parameters should be sampled and analyzed from a sampling grid of 100 stations which should cover all offshore bases and regions surrounding them. The water column should be surveyed bi-monthly but the interstitial waters need only be sampled once.

22. Identification of operation-specific substances and their potentially deleterious, physical, and chemical characteristics should be made. Those of greatest concern should be incorporated into the base line in the monitoring program.

5. Physical Oceanography

The first recommendation proposed by the Southern California Academy of Science was a synthesis of all historic data including oceanographic and surface meteorology: (a) The historic data would improve the knowledge of average trans-

ports and seasonal variations (b) analysis of T-S structure will reveal more information on subsurface and bottom flows (c) review of areas where insufficient data exists to determine dispersion and transport of water masses (d) review of the kinds of data CALCOFFI; CFG; AHF; and other pertinent data, (e) develop background imformation on eddies and eddy structure. Once the historic data has been centralized and analyzed, the following recommendations should be followed in order to provide a sufficient bases upon which physical oceanographers can provide predictive information regarding the ecological effects of offshore drilling on marine life.

First, scientists should analyze and determine the eddy patterns and structures in the Southern California bight.

Eddies may play a key role in determining the location of platforms, i.e., in the center of an eddy or on the edge would make a major difference in the dispersal rate of any enrichment material added to the water. Therefore, some specific studies related to eddy structures should be conducted. The CALCOFFI sampling grid is too large to adequately define small-scale eddies. Additional stations should be added to the CALCOFFI sampling grid in areas of particular interest and in the proposed lease sites as well. A specific study should be conducted on the scale, life history, and depth structure of an eddy.

A base line program should include detailed studies of a few eddies to determine structure and life history. The eddies can be identified and located by aerial surveys. Thereafter, the studies will continue by shipboard operations. The ship-board would include drogues, drift cards, detailed T-S observations to describe the eddies and AxB T's to study structure.

Extensive current studies should be conducted in order to fill in existing information gaps. The total current structure should be determined in a particular study area. Knowledge of the current structure will be used to determine the total residence time of water in the offshore basins. In addition, bottom currents in the study area should be studied and analyzed. In conjunction with current studies reliable and consistent offshore wind data should be reported. It is strongly recommended that the San Nicolas weather station should be continued in order to contribute valuable data. Efforts should be made to continue to follow and monitor existing programs and augment where necessary.

Scientists strongly urged that existing platforms in the Santa Barbara Channel be instrumented with current observations and surface meteorological equipment. It is also recommended that future platforms be instrumented with similar equipment as they are built and installed.

Attempts should be made to encourage merchant marine shipping to send meteorological data near shore. The study should also include the establishment of sealevel tide stations at offshore islands to monitor gross flow between the islands

and the mainland.

The study should also consider the aspects of water exchange in deep basins and exchange between basins as it relates to dispersion of pollutants.

Scientists strongly recommend that a study be conducted of natural oil seeps in order to develop a model for the dispersion and floculation processes involved in oil spills originating at the bottom.

We urge that the necessary studies be conducted so that prior to any leasing we know the real environmental and economic consequences of the proposed.

L. The Onshore Land Use Impacts of O.C.S. Development

1. Onshore Land Impacts

To a great extent, the influx of onshore activities resulting from O.C.S. development is dependent on the size of the proposed action and the prior presence and extent of off-shore oil and gas development. The National Ocean Policy Study[151] indicated that:

> Actual impact of O.C.S. development on the economic structures of the coastal zone will depend on a number of variables, such as:
>
> 1. Location of oil and gas fields.
> 2. Location of leased tracts in relation to shipping lanes, recreation areas, wild-life refuges, and so on.
> 3. Expected size of the reservoirs, estimated production rates, and type of production.
> 4. Geological, geophysical, economic and other data to indicate whether oil and gas are likely to be transported ashore by pipe-line or tanker.
> 5. Expected size and location of required stor-age facilities.
> 6. Whether rigs and platforms will be constructed locally, or imported from traditional sup-plier states.
> 7. Existing infrastructure and industrial ca-pacity.
> 8. Whether only necessary or also optional pro-duction facilities include petrochemical plants.[152]

While the primary land use impacts will differ from site to site, depending on the above criteria, most of the related onshore

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151 The National Ocean Study Policy was established pursuant to Senate Resolution 222.

152 Senate Committee on Commerce, <u>Outer Continental Shelf Oil & Gas Development and the Coastal Zone</u>, 93 Congress, 2d. Session, Committee Print (1974), at [illegible]3. Hereinafter cited as <u>NOPS O.C.S. Study</u>.

activities will require exclusive use of land in coastal areas where intense competition for use of land occurs.

The proposed action would necessitate development in geographic areas of the United States "that have experienced little or no history of offshore oil and gas operation,"[153] as well as in areas which have existing social infrastructures and industrial support capability. Onshore activities related to O.C.S. development having primary land use impacts would include, but are not limited to:

> navigation and access channels;
>
> crew boat basins, equipment storage depots, and warehousing areas;
>
> clean-up and containment equipment staging areas;
>
> pipeline terminals and corridors;
>
> tank farms, trans-shipment and road or transportation accommodation facilities;
>
> refineries, petrochemical complexes, and supporting construction industries.

Water and air pollution associated with these onshore activities will occur, though possibly ameliorated by the use of various control technologies.[154] Impacts on aesthetic and scenic values may be adverse and displeasing as a consequence of construction of onshore terminals, product storage facilities, and pumping stations, if these facilities are located in areas valued for

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153 Bureau of Land Management, Draft Environment Statement of Proposed Increase in Acreage to be Offered of Oil and Gas Leasing on the Outer Continental Shelf, DES 74-90, Vol. I (October 18, 1974), at 7. Hereinafter cited as Draft E.I.S.

154 Council on Environmental Quality, O.C.S. Oil and Gas - an Environmental Assessment, at 7-78. Hereinafter cited as CEQ Study.

their natural or scenic qualities. Noise pollution from vehicular traffic to and from these facilities may also result, reducing aesthetic enjoyment of scenic and natural areas. The severity of these impacts on the land is also keyed to the pace of development; generally speaking, the faster the development, the shorter the available time for planning for related impacts.

None of the preceding description contends with major onshore land use impacts associated with the potential catastrophe of an oil spill, which, in light of recent freighter accidents near Hong Kong and off the Scottish coast, provides cause for concern and evaluation. Such an occurrence --whether accidental or chronic -- could also have its onshore land impacts. If a spill reached the shore, the primary shoreland impact would be, dependent on severity, the potential for preventing citizen use of the beaches. A spill could destroy existing estuary populations. The secondary impacts include a loss in coastal tourist trade in commercially productive tourist centers with accompanying effects of diminution in land value and the aesthetic enjoyment of the coast. This is very significant in light of the fact that the tourist industry is the third largest industry in California.

Although the possible primary onshore impacts appear substantial, some of the most significant environmental impacts are secondary impacts. These include land use impacts on the affected community infrastructures comprised of physical and

service systems, and business and governmental institutions. Particularly with rapid population increases related to O.C.S. development, induced impacts could be suffered by the water supply and sewage system, the energy supply, residential, recreational, commercial and industrial facilities, and various transportation sectors.

Support services for O.C.S. development are also bound to have a contributive impact. For each community affected, for example, there will be needs for additional schools, law enforcement and fire protection, health care and hospital facilities, sewage handling, solid waste management, and government planning and organization.

2. Evaluation of Adequacy of Draft E.I.S.

The draft E.I.S. devotes 776 pages[156] to the section entitled, "Description of the Environment"; essentially an extended geographic gazette. The draft E.I.S. provides an inadequate treatment of the land use empacts of O.C.S. development:

1. Its contents do not actually define or describe the amount of land that petroleum operations may require for each region.

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155 Id. at 7-13.

156 Draft E.I.S., supra n. 153, at Vol. I pp. 173-792; and Vol. II pp. I-157.

2. The quality or types of land and soil that are suitable for onshore activities are not set forth.

3. Significantly, the draft E.I.S. fails to provide a working discussion of the capability of the shorelands to sustain the many particular onshore primary and secondary activities mentioned above.

4. The draft E.I.S. fails even to mention a method to evaluate the capacity of the described land to carry and endure the additional anticipated burdens created by new onshore activity. To say an area is already industrialized says nothing about its ability or inability to sustain more growth in a rapid fashion.

5. Pages 46-54 of Volume II presents cargo transportation figures by volume for the nation's ports. Yet no inventory of supporting industrial facilities is provided in the draft E.I.S.

6. Also lacking is any data attempting to inventory or estimate the acreage available to support and sustain offshore drilling activities in each harbor. The draft E.I.S. should at least suggest minimum thresholds for adequate service.

The section entitled "Proposed Land Use Policy and Planning Assistance"[157] uses <u>only</u> pipeline corridor studies in illustrating land consuming uses resulting from this expected lease program. None of the many other land consuming uses are mentioned. Under "Potential Special Field Studies",[158] the only onshore activity targeted is again, "Pipeline corridor studies involving suitable O.C.S. and onland area inaffected states." This Section Title misleads a reviewer to expect a more exhaustive discussion.

In Volume II, the discussion under "Pacific Coast Region, Resources of the Coastal Zone"[159], notes that the "Channel Islands represent a great potential ecologic and recreation resource." A consideration missed by this discussion is the potential for these islands to serve as bases for storage and staging of emergency spill containment and/or clean-up equipment in support of O.C.S. development. The distance from current harbor complexes -- Los Angeles/Long Beach and Carpenteria/Oxnard - creates pressure to locate such support facilities on the Channel Islands which are closer to the prospective Santa Rosa Ridge and Cortez-Tanner

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157 <u>Id</u>. at Vol. I. p. 124.

158 <u>Id</u>. at Vol. I p. 136.

159 <u>Id</u>. at Vol. II p. 31.

Banks lease areas. Again the draft E.I.S. fails to evaluate the impact of such facilities on these isolated eco-systems or provide any estimate of loss of land for recreation.

The draft E.I.S. on page 235 of Volume II continues the discussion of onshore impacts in Southern California by indicating that constraints on increased land utilization are solely a problem of refinery expansion. No recognition of other secondary use conflicts is presented.

When enumerating "Conflict with Other Uses of the Land" (Unavoidable Adverse Environmental Effects),[160] the E.I.S. mentions only the single season inconvenience to agricultural land during the period of pipeline construction and burial. Other consumptive land use impacts -- beyond mere pipeline installation inconvenience -- should have been throroughly discussed.

Finally, under the subsection "Land Resources" that would be an "Irreversible and Irretrievable Commitment of Resources",[161] the only identified acreage consumed as a result of the proposed action is for pumping facilities, pipelines, and pipeline terminals. No discussion or estimation of onshore land uses could possibly be considered exhaustive with such limited scope.

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160 Id. at Vol. II p. 316.

161 Id. at Vol. II pp. 321-322.

These inadequacies suggest that an effort to achieve brevity[162] has resulted in an over-simplification. By constantly limiting illustrations to only the most visible primary impacts, the E.I.S. voids, and thus removes from necessary consideration, many of the land use consumptions that will befall the lands adjacent to the proposed O.C.S. activities.

3. Consideration of Impact on Local Government of Proposed Action and the Potential for Dislocation.

As visible as primary land activities associated with O.C.S. development are, it is in the realm of the secondary land consumption that all non-federal units of government will be impacted and will be required to respond. Yet the E.I.S. only once discusses the full spectrum of these impacts on local government units -- and even then chooses to devote but two sentences:

> The resultant demand for services -- for example schools, hospitals, transportation facilities, residential housing, office space, and electric and water utilities, would require considerable planning and increases in local government expenditures." [163]

Remarkably, in these two sentences. B.L.M. recognizes clearly where the responsibility for planning for these impacts will lie -- on the local government. However, the document fails to analyze the response capabilities of the local governments.

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162 *Id.* at Vol. I p. 32.

163 *Id.* at Vol. II p. 246.

While B.L.M. is not required in this instance to discuss the response capabilities of every town and county government along the adjacent coastlines of the proposed program, it could have presented the means and methods by which local land impacts can genuinely be assessed and evaluated. There should be examples and/or models by which local units can:

(1) Assess and predict probable land needs, both primary and secondary.

(2) Establish priorities.

(3) Anticipate rates of land consuming service (roads, schools, water systems) demand growth.

(4) Evaluate flux of needs in number (3) over time.

(5) Avoid knee-jerk, crisis-driven land use planning.

The E.I.S. comes closest to answering the above needs in its "Environmental Impacts of the Proposed Action" in which it discusses the estimated primary and secondary employment impacts of O.C.S. activity based on an April, 1974 C.E.Q. Study.[164] Quoting directly from that study, the E.I.S. projects increased primary and secondary employment impact associated with development of the Atlantic O.C.S. at 144,000 and 318,000 jobs, respectively, for the Atlantic region. By contrast, Gulf South Research Institute[165] projects levels of

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[164] Id. at Vol. II pp. 219-250.

[165] NOPS O.C.S. Study, supra n. 152.

20,900 and 65,690 for primary and secondary employment increases for the same Atlantic region. In addition, an extrapolation from a Rand Corporation Study[166] produces an estimate of 18,620 new primary production employees. At fourth study done by Sherman Clark Associates[167], further supports these latter two studies. However, the National Ocean Study Policy warns that the divergence between the C.E.Q. study study estimates and the others may result from the use of different data sets and possibly unwarranted extrapolations:

> "Whatever the reason for the vast discrepancies between C.E.Q. figures and those of the other studies may be, it is clear that data on the employment impact of offshore oil and gas development in the coastal zone are insufficient to serve as guidance for policymakers. The difference in projected population increases is so vast as to have a serious impact on planning for schools, hospitals, roads, etc." [168]

The above discussion should not be easily brushed aside. The two paragraphs below clearly demonstrate the critical nature of the needs that flow directly from knowledge of externally induced population increases.

> Offshore oil and gas developments are part of the larger problem of competing uses of the Coastal Zone, problems which can only be solved through comprehensive planning. Oil and gas development in the O.C.S will put additional demands on the use of land for tank-frames, separation facilities, and so on. During the construction stage in

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166 Id.

167 Id. at 12.

168 Id. at 12.

particular, new demands will be made on the infrastructure of the coastal zone adjacent to the offshore fields, and the growing population associated with the various stages of development will need housing, schools, hospitals, recreational facilities, etc. A review of the literature on employment associated with offshore petroleum development shows great variation and discrepancy in assumptions about the extent of employment effects, and advanced planning for offshore development in new frontier areas has become very difficult. As planning for additional commercial, recreation, and service-oriented facilities is dependent on accurate employment figures, additional studies of the economic impact of offshore petroleum development must be undertaken.

> If the discrepancy in employment data is too large, as is the case in some of the studies made on employment impact associated with development of the Atlantic O.C.S., it will be impossible for state planning agencies to assess accurately additional demands on the infrastructures and front-end capital required to provide additional social services for a growing population. [169]

While it is beyond the scope of this review to estimate cash flow problems that might be encountered by government in regions adjacent to O.C.S. Operations, the following cash cost for infrastructure services does mean that some portion of these costs are spent on physical structures consuming land in coastal regions. For example, under tax and revenue structures, the State of Louisiana claims that it sustains net, onshore costs in excess of assignable tax revenues, of $38 million per year in support of offshore operations beyond the 3-mile limit in order to provide services to people who work in federal waters. [170]

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[169] *Id.* at 9.

[170] *Id.* at 69.

Texas also has recently released a study[171] which estimates the potential costs to the State as a result of new O.C.S. leases in the Gulf of Mexico. It concluded that the net cost to State and local government, in excess of new revenue, will be $62.1 million per year. Much of this cost will be tied up in providing land consuming facilities.[172]

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171 State of Texas' Office of Information Services, Benefits and Costs to State and Local Governments in Texas Resulting from Offshore Petroleum Leases on Federal Lands, Report # 0025-029-1174-NR (Nov. 14, 1974).

172 Id.

M. The Lesson of Santa Barbara

The 1969 Santa Barbara oil spill stands out conspicuously in the minds of all coastal communities as the paradigm example of the potential hazards associated with offshore drilling. No discussion of the environmental and economic impact of O.C.S. development can be considered complete without a review of the Santa Barbara disaster. Nonetheless, the draft E.I.S. is notable for the absence of any analysis of the Santa Barbara spill. In this section, we shall analyze that spill - its causes, its consequences, and, most of all, its lessons for future offshore development.

1. <u>The Anatomy of an Oil Spill</u>

On January 29, 1969, a blowout occurred at the Platform A offshore rig near Santa Barbara operated by Union Oil Company. Thousands of gallons of oil from well A-21 began spewing into the Santa Barbara Channel, as men worked feverishly to regain well control. The well continued to blow out of control for ten days, until the well bore was choked with cement on February 7, 1969, and well control was apparently regained.

Unfortunately, the spillage began again a few days later. Well A-21 had been drilled to a depth of 3,479 feet but the well bore was uncased below 239 feet. Oil began coming up the uncased bore and then escaping into

shallow oil sands and reaching the surface through pores and fissures. All attempts to control this leakage have failed, as oil continues to flow from under Platform A to this very day. To make matters worse, in December, 1969, human error resulted in a ruptured underwater pipeline between Platform A and the shore, discharging more oil into Santa Barbara waters.

By May, 1969, over 3,250,000 gallons of oil spilled into the ocean according to accepted estimates. Allen, Estimates of Surface Pollution Resulting From Submarine Oil Seepage of Platform A and Coal Oil Point, 1969. An oil slick of over a thousand square miles developed off the Santa Barbara coast extending from northwest of Santa Barbara to Ventura and Oxnard on the south and east beyond the pristine Channel Islands, completely engulfing Anacapa Island. Oil came ashore in heavy dosages to pollute beaches from Santa Barbara to Ventura and on the Channel Islands. Santa Barbara harbor was inundated. Some 390,000 gallons of oil came ashore along a 7-mile stretch of coast at Santa Barbara, while over 1.3 million gallons contaminated 55 miles of mainland coast and 25 miles of Channel Islands coast. Easton, Black Tide, 1972.

There were serious delays in initiating and co-ordinating contingency plans for oil containment in the first hours and days following the blowout. As it was, containment

and recovery efforts proved woefully inadequate. Over 89,000 gallons of chemical dispersants were discharged into Santa Barbara Channel to no avail, although the chemicals did have deleterious effects on marine life. Easton, Black Tide, 1972. Oil containment booms and skimming devices were useless in open seas, but did prove effective in preventing pollution of several harbor facilities, with the notable exception of Santa Barbara. Straw was helpful in cleanup efforts, although beach sand removal was also necessary. Steamcleaning was the only way to remove oil from stained rocks, but mussels and other rocky intertidal organisms were destroyed in the process.

The cause of the disaster? Officially, the cause of the blowout was the pulling of a "balled drilling bit" which had plugged the well bore and created a loss of mud pressure. U.S.G.S. Report on Lease OCS-P 0241, 1969. Contributing factors were the use of mud weight too light to control formation pressures, the use of mud of improper viscosity, and inadequate mud control indicators, all of which caused a loss of sealing potential. The U.S.G.S. Report also claimed that mud circulation was lost for the 48-hour period prior to the blowout, an indication of pending trouble. Controversy also developed over the depth of well casing. The Department of the Interior

had waived its regulations regarding installation of well casing to a depth of 880 feet because of inadequate geologic structures to which the casing could be attached. They permitted Union to cease cementing well casing at a depth of 239 feet. Regardless of whether lack of adequate casing was a cause of the intitial blowout, it appeared to be an instrumental factor in the leakage, which has continued to occur even after the well bore was cemented shut.

Upon whom, then, should responsibility for the blowout be placed? Direct responsibility must be borne by Union Oil Company for a series of errors: improper training in blowout prevention control, poor inspection and safety procedures, use of wrong mud weights and mud viscosity, lack of adequate casing, lax attitude on the part of management toward safety and just plain human error. Ultimately, however, the federal government must bear responsibility for the spill in view of its inadequate understanding of the dangers of drilling in geologically unstable areas, inadequate regulations and safety standards, insufficient inspection procedures, lack of access to critical information necessary to make an independent review of drilling operations, and its general inability to effectively monitor offshore oil activities.

2. Damage to Marine and Coastal Environment

It is virtually impossible to assess the total

long-term damage to the marine and coastal environment resulting from the 1969 oil spill. One scientist, noting that the number of marine organisms appeared to be roughly comparable to pre-spill populations, has concluded that the spill's effect on marine life was negligible. Straughan, Biological and Oceanographical Survey of Santa Barbara Channel Oil Spill, 1969-70, 1971. Others dispute that claim, arguing that no adequate baseline information was available to make such comparisons and charging that the study included no physical or chemical analyses of subtle toxic effects. Blumer, Scientific Aspects of the Oil Spill Problem, 1971; Connell, A Review of Straughan, 1972.

Whatever the long-term damage to the marine ecosystem, the short-term effects were undeniably severe. Dr. Max Blumer of Woods Hole has summarized the potential effects of crude oil pollution:

1. Direct kill of organisms through coating and asphyxiation.
2. Direct kill through contact poisoning of organsims.
3. Direct kill through exposure to the water soluble. toxic components of oil at some distance in space and time from the accident.
4. Destruction of the generally more sensitive juvenile forms of organisms.
5. Destruction of the food sources of higher species.

6. Incorporation of sublethal amounts of oil and oil products into organisms resulting in reduced resistance to infection and other stresses (the principal cause of death in birds surviving the immediate exposure to oil).

7. Incorporation of carcinogenic or potentially mutagenic chemicals into marine organisms.

8. Low level effects that may interrupt any of the numerous events necessary for the propagation of the marine species and for the survival of those species which stand higher in the marine food web.

Many of these effects on the marine environment manifested themselves following the Santa Barbara oil spill. The following table represents a recent estimate of the number of organisms killed or amount of biomass removed as a result of the oil population and oil cleanup activities: Foster, The Santa Barbara Oil Spill: A Review of Damage to Marine Organisms, 1974.

Habitat and Organisms	Damage
Rocky Intertidal Zone	
Barnacles	8,770,000 killed
Surf grass	16 tons of blades & attached algae & invertebrates removed

Habitat and Organisms	Damage
Polychaete worms	80,900 killed
Limpets	51,800 killed
High Intertidal crevice fauna (mostly arthropods)	20,000 killed
Mussels	30,000 killed
Sandy Beaches	
Sandy beach macrofauna	15,000,000 removed during beach cleanup
Deep Subtidal Zone	
Benthic invertebrates	6,000 tons lost
Neritic Habitat	
Marine birds	9,000 killed (60% loons and grebes)

Organisms in the rocky intertidal zones suffered severely. The smothering effect of the oil killed barnacles, surf grass, organisms living in the habitat provided by surf grass such as limpets and polychaete worms, and many other species which commonly inhabit the cracks and crevices of the intertidal and splash zones such as periwinkles, pill bugs, flatworms, sand hoppers, limpets, beetles, etc. Sandblasting and steamcleaning to remove oil stains from rocks appear to have killed many intertidal organisms. A team of researchers has estimated that 60% of the mussels in Santa Barbara harbor were killed as a result of steamcleaning. Jones, et al, Just How Serious Was the Santa Barbara Oil Spill?, 1969.

Long term damage to rocky intertidal organisms also occurs as a result of loss of habitat due to the build up of dried oil on rocks. Sessile organisms do not adhere to or grow as well on dried oil. Over 11 million square feet of rock on public land are still contaminated with oil from the Santa Barbara oil spill. U.R.S., Physical Assessment and Cleanup-Restoration Cost Estimate of Coastal Areas Contaminated by Material Related to the 1969 Santa Barbara Oil Spill Incident, 1974. Continued leakage at Platform A causes further immediate damage to organisms as it reaches shore and also contributes to additional contamination of the rocks. Possible long term effects include reduction in breeding success due to sublethal oil contamination, indirect reduction in predatory species resulting from loss of prey, and the uptake of hydrocarbons by higher order species from intertidal organisms. These consequences have not been investigated.

Sandy beach microfauna, which includes sand hoppers, sand crabs and blood worms, were killed primarily as a result of sand removal during beach cleanup operations. Shallow subtidal organisms, which include giant kelp, other plants, and invertebrates, do not appear to have suffered seriously. Damage to benthic marine life was substantial, however, because much of the oil from the spill ended up on the bottom.

Marine bird losses provide the most dramatic

example of the environmental consequences of the Santa Barbara oil spill. Oil disrupts the water repellent properties of feathers, causing birds to become waterlogged and sink, and also destroys the thermal insulating properties of feathers, causing loss of body heat. Birds also die from oil ingested during preening or feeding. Diving birds like the loon and grebe were thus particularly affected. Attempts to save birds by cleaning their feathers proved futile. Possible long term effects include reduction in breeding success and the uptake of hydrocarbons.

As noted before, long-term effects of the spill are difficult to estimate. Nonetheless, Foster, supra, concludes, "The continued presence of oil from the initial spill on solid substrata and in sandy beaches, the observed changes in deep subtidal benthic communities, and the fact that the oil continues to escape from the platform all suggest that the Channel has not recovered."

3. Economic Impact of the Spill

Estimating the cost of the damage resulting from the Santa Barbara oil spill is a very difficult undertaking. Losses to property and the cost of clean up operations have a readily determined market value. Yet what price is to be placed upon the life of a bird or a sea lion, or upon the loss of aesthetic and recreational pleasures? Despite such difficulties, efforts have been made to quantify in economic

terms the losses occurring as a result of the Santa Barbara oil spill. These are summarized below.

(a) Resources Lost

The amount of oil spillage from Platform A is estimated to be approximately 80,000 barrels. At the 1969 world market oil price of $2.15 per barrel, the value of the lost oil to Union Oil Company was $130,000. Mead and Sorensen, The Economic Cost of the Santa Barbara Oil Spill, 1970. At today's prices, the value lost would be several times that amount.

(b) Well Control and Beach Cleanup Operations

The cost incurred by Union Oil Company (and its three partners - Gulf, Mobil and Texaco) for beach cleanup, oil collection, and oil well control was $10,487,000. The direct cost incurred by governmental agencies for cleanup operations, disaster monitoring, beach and offshore inspection trips, etc., was $639,200. Mead and Sorensen, *supra*.

Yet the Santa Barbara beaches are still contaminated. Oil stained rocks destroy the habitat of rocky intertidal organisms, while oil deposits buried in beach sand can affect the habitat of sandy beach organisms. U.R.S., *supra*, estimated that the total cost to clean up and restore contaminated rocks and sand on publicly owned parks, beaches

and tidelands would range from $11.8 million to $30 million.

(c) Damage to Biological Life

Sorensen, Economic Evaluation of Environmental Damage Resulting From the Santa Barbara Oil Spill, 1974, has developed two alternative approaches for valuing the short term damage to marine life as a result of the spill. The first approach is to estimate the cost of replacing the dead or damaged marine organisms. Using Foster's estimate of the number of organisms killed and of the unit prices developed in conjunction with biological supply firms, the following economic value was derived:

Organism	Foster Estimate of Number Killed	Value
Buckshot barnacle	8.7 million	$870,000
Surf grass Alga	16 tons	$5,000 (reseeding)
Hydroids	5.9 million	$1,175,860
Limpets	51,800	$19,425
Polychaete worms	80,900	$12,800
High intertidal beetle	1,700	No quotation available
Amphipods and Isopods	18,300	$4,575
Mussels	30,000	$9,000
Red worm	10.7 million	$2,140,000
Sand crab	2.1 million	$63,000
Beach hoppers (killed in beach cleanup)	780,000	$23,400

Organism	Foster Estimate of Number Killed	Value
Deep Subtidal Organisms (Mollusks, worms, brittle stars)	24 million	$6,000,000
California sea lions	10	$750
TOTAL DAMAGES		$10,323,910

The information costs of determining long-run damages must also be added to the short-run costs assigned above for replacement, bringing total replacement costs to $11,323,910.

Sorensen's alternative approach to damage assessment is to measure the short-term reduction in resource yields. In this approach, the contribution of the resource to the food chain, ultimately represented in fish catch, is measured and added to the yield in terms of amenity values of the intertidal and other organisms which were destroyed. Added to this is the information cost of determining long-run damage. Using a resource yield theory of short-run damages, Sorensen estimates the economic cost of the spill to be $6,831,624.

(d) Physical Damage to Beach Environment

Following the 1969 oil spill in the Santa Barbara Channel, sand was removed from contaminated beaches during cleanup operations. Any cleanup operations which occur in the future to remove remaining contamination will also result in a loss of sand.

U.R.S. has estimated the value of sand on public land lost by 1969 cleanup operations to be in a range from $185,960 to $346,370. The value of sand lost by future cleanup of remaining contamination on public land ranges from $20,477 to $283,060. The value of sand on private land lost by 1969 cleanup operations or by future cleanup activities was not computed, but would surely swell the above figures. The large variation derives from the fact that beach sand is regarded by some as specialty sand.

Another physical resource of the beach damaged by the 1969 oil spill is driftwood. Considerable quantities of contaminated driftwood were burned or hauled away. Driftwood has commercial value as firewood and as decorative art. U.R.S. estimates the total value of lost firewood to range from $1.2 to $1.8 million, and of lost decorative driftwood to be $20 to $26 million, respectively.

(e) Indirect Costs

Indirect costs to local governments and to the State of California occurred in a variety of ways. Beaches owned by state and local governments diminished in property value and yielded interim rent and utility losses. These losses have been appraised at $3.9 to $5.1 million for the State of California, $2.6 to 3.2 million for the City of Santa Barbara, $234,000 to $326,000 for the County of Santa Barbara, and $215,000 to $280,000 for the City of Carpenteria. These losses, which range from $6.9 to $8.9 million do not

include the cost of cleanup operations, nor do they include losses suffered by local governments in Ventura County or by private landowners. (Affidavit of George Hamilton Jones in State of California v. Union Oil Company, United States District Court, Central District of California, No. # 69-1068-RM.).

The State of California and local governments also suffered lost sales tax revenues because of lost beach use and lost tourism. The spill cost the State of California $17 million in sales taxes, the County of Santa Barbara $1.1 million in sales taxes and $500,000 in property taxes, the City of Santa Barbara $3 million in sales taxes and $600,000 in bed taxes, and the City of Carpenteria over $566,000 in tax revenues. These losses do not include losses by local governments in Ventura County. (Testimony of A. Barry Capello, City Attorney of Santa Barbara, before California State Lands Commission, November 1974).

Another environmental and socioeconomic impact of the spill was the diminution of public services to local communities. Reduced public services occurred as a result of redeploying existing resources to handle the spill and of lost tax revenues. No value has been estimated for the loss of public services.

(f) Commercial Losses

The commercial fishing industry suffered the most immediate damage from the oil spill. Fishermen were unable

to get boats out of Santa Barbara harbor because of oil containment booms. There was little fishing to be done anyway because of fear of oil damage to vessels and equipment and contaminated catches. Sorensen, supra, calculated damage to commercial fishermen to be $804,250.

No damages to tourism have ever been estimated because losses to local businesses were cancelled out by gains in other geographical areas. The loss in bed tax revenues by the City of Santa Barbara and the City of Carpinteria, however, indicates that the losses were substantial.

(g) Private Losses

Sorensen supra, estimates that the recreational value of beach experiences lost to residents and visitors was $3,150,000. Beachfront real estate was damaged by the spill and property values declined. Sorensen, supra, estimated the loss in property value to be $1,197,000.

4. The Lessons of Santa Barbara

What, then, are the lessons of the 1969 Santa Barbara oil spill?

(a) Oil Spills are Inevitable

Stricter regulations, improved blowout prevention training, technological advances, and more frequent inspections have reduced the probability of a Platform A type of blowout. Yet oil industry engineering experts regard human error as the primary cause of blowouts. No one can guarantee against a repetition of a Platform A blowout.

While the probability of a major blowout has been reduced since 1969, the probability of a major oil spill occurring as a result of increased tanker traffic has steadily increased. This is especially true of Santa Barbara Channel, which is already the busiest shipping lane on the Pacific coast. Increased oil tanker traffic from Alaska coupled with increased traffic from resumption of offshore oil drilling substantially increase the probability of an oil tanker colliding with another vessel or, worse yet, with another tanker or with an offshore platform. The draft E.I.S. admits the likelihood of a major oil spill.

Many massive oil spills have in the past received world-wide attention. Major spills include the "Othello" tankship collision (3-20-1970; 420,000 - 700,000 barrels); the Tarut Bay pipeline rupture in Saudi Arabia (4-20-1970; 100,000 barrels); the South Timbalier Block 26 OCS-G1870 Shell Oil Company offshore platform explosion in the Gulf of Mexico (12-1-1970 to 4-16-1971;

53,000 barrels);[173] and the collision of two Standard Oil of California oil tankers at the entrance to San Francisco Bay (1971; 20,800 barrels).[174]

On January 17, 1975, the C.B.S. evening news reported on the chronic oil pollution occurring at Bantry Bay on the southwest coast of Ireland.[175] Prior to installation of a Gulf Oil supertanker port, Bantry Bay was an unspoiled natural area rich in scenic and aesthetic values which attracted numerous tourists. Since the installation of the supertanker facility three years ago, however, there have been over a dozen major and minor oil spills. There have been two major spills in the last three months. The beaches, estuaries, and nearshore coastal environment have suffered severe and continuing effects. A spokesman for the Gulf Oil Corporation which owns the supertanker facility admitted in an interview that oil spills, which are the result of human error, are an inevitable consequence of any significant oil production and transportation activity.

Potentially even more dangerous than major oil spills are the cumulative effect of chronic small or moderate spills

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[173] Easton, Robert, "A List of Major Oil Spills", Black Tide, Delacorte Press, New York, 1972 (p.297).

[174] Chan, Gordon L., "A Study of the Effects of the San Francisco Oil Spill on Marine Organisms", Proceedings of Joint Conference on Prevention and Control of Spills, 1972 (pp. 741-759).

[175] C.B.S. Evening News, January 17, 1975.

emanating from tankers, platforms, and broken underwater pipelines. Such spills are an almost daily occurrence. Only a few weeks ago (Los Angeles Times, January 15, 1975), an 18 mile long oil slick appeared in Santa Barbara Channel and was believed to have been discharged by a passing tanker. The draft E.I.S. admits that many small and moderate spills will occur as a result of increased O.C.S. development.

(b) Oil Spills Cause Extensive Environmental Damage and Economic Loss

Oil spills do serious short-term and long-term damage to the biological life and physical characteristics of the marine and coastal environment. Oil containment and recovery techniques do little to minimize the ecological impact of a spill. The economic costs of a major spill are also extensive, causing losses to many people directly and indirectly. The total cost of the 1969 oil spill, for example, has never been calculated. Indeed, its effects are still being felt.

(c) Liability Mechanisms are Obsolete

The Santa Barbara oil spill demonstrates the total inadequacy of present liability mechanisms to provide compensation for losses suffered by government, industry and private individuals. It was 1974 before suits by local governments and the State of California against the oil companies were finally resolved. Private suits continue. Uncertainty about compensation of losses delays cleanup and restoration. Also, some losses were never compensated, such as the loss of tax revenues by the City of Santa Barbara, the loss of tourism or the loss of marine resources.

Before O.C.S. development proceeds further, provisions should be made to determine liability quickly and to require the oil companies or the federal government to make compensation without unreasonable delay. We recommend that an oil spill liability fund is needed to minimize the economic impact of oil spills. Ideally, the managers of such a fund would include representatives of local government. This recommendation is set forth in greater detail below.

(d) Inability of Interior Department to Monitor Drilling Activities

One of the primary lessons learned as a result of the Santa Barbara spill is that the U.S. Geological Survey and the Interior Department were not able to monitor offshore drilling activities in an effective manner. While regulations have been strengthened and inspections made more frequent, there are still reasons to doubt the monitoring capability of the Interior Department. The oil companies still control much of the information necessary for effective supervision. Enforcement of penalties for violations of safety regulations is virtually non-existent. A recent report indicates that U.S.G.S. often issued warnings only. Also, proposed orders are regularly circulated among the industry in the Federal Register. In view of the enormous ecological and socioeconomic impact of oil spills on local communities, monitoring and supervision of offshore drilling activities needs substantial improvement.

N. Diminution of Land Value

The draft E.I.S. does not discuss diminution of land values that result from offshore oil and gas development. The combination of negative visual impacts of drilling platform rigs, potential oil spills, increased noise pollution, and deterioration of aesthetically valuable coastal shores all have an adverse effect on surrounding residential and public property.

As a result of the 1969 oil spill, for example, the cities of Santa Barbara and Carpenteria experienced an estimated diminution of land values of approximately $2,801,000 to $3,453,000. In addition, the State of California incurred a loss of approximately $3,850,000 to $5,155,000 in utility values of state parks and beaches. These substantial losses do not include the millions of dollars which state and local governments expended for cleanup costs and business-related losses.

Oil producers argue that O.C.S. activity will result in new jobs, new businesses to support offshore drilling activities and new tax revenues. Yet recent studies indicate that state and local governments incur excessive cost in providing direct and indirect provisions such as education, health and safety facilities for increased population.[176] A report from the Texas State Senate

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176 The Senate of the State of Texas, O.C.S. Production Cost to State and Local Government (November 22, 1974), at 3.
". . . cost to state and local government associated with this level of offshore development include the provision of such public services as public education, police protection, highways and streets, and health services to the public directly and indirectly associated with the offshore production."

claims that revenue to Texas from the Gulf of Mexico O.C.S. activity is approximately 48.9 million dollars. The cost incurred by state and local government to provide services is approximately $111,000,000. Thus, according to the study, the citizens of Texas are paying approximately 62.1 million dollars for services to support O.C.S. drilling.[177]

Another ramification, of O.C.S. development is increased onshore activity. Accelerated construction of refineries, pumping stations, etc., must be provided to support offshore activity. Those onshore activities attract additional vehicular transports, thus necessitating more highways and roads. The end result is a diminution of land value, irreparable loss of the aesthetically valuable coastal resources, increased noise and air pollution, and additional and burdensome state and local expenditures. These onshore activities have been described as follows:

> . . . generally, however, no provision is made to spare the average taxpayer from the expenses which occur from the destruction of adjacent shoreline areas as a result of severe problems of beach erosion . . . .
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> . . . Cargoes of manufactured goods, petroleum, . . . worth millions of dollars flow through the ports of the local shoreline. Millions of dollars worth of oil are produced from artificial islands, oil platforms, pads and estuaries and on the beaches of the local area. The economic activity along the

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177 Id. at 8. See also McCray, William C. and Grabb, Herbert W., Benefits and Cost to State and Local Governments in Texas Resulting from Offshore Petroleum Leases on Federal Lands, Management and Science Division, Office of Information Services, Office of the Governor, Austin, Texas (November 15, 1974).

> shoreline is not yet integrated with the life support systems necessary to sustain life on earth; rather, it would appear that the economics of business as currently practiced include environmental deterioration and degradation as a component in the determination of the financial profit of . . . private enterprise. 178

Thus, state and local governments are significantly impacted by O.C.S. development. Yet present leasing provisions of the Department of the Interior do not provide for compensation to state and local governments. Given the potential adverse impacts on state and local governments the present O.C.S. leasing procedure should be amended. In conjunction with the Department of the Interior, oil producers should be required to consult with state and local governments before determinations are made on whether an activity would degrade local environmental and land values. Without such a procedure, the present O.C.S. leasing system deprives state and local governments of a meaningful voice in the determination of their own land uses and may constitute a denial of due process and an unlawful taking of land without adequate compensation. We discuss below the various factors that contribute to the diminution of land values.

Tangible structures in offshore waters diminish the scenic value of coastal waters. Federal agencies (the National Park Service, Bureau of Outdoor Recreation, and the Bureau of Sport Fisheries & Wildlife) have reported that platforms and rigs

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178 Fay, Rimmon, Southern California's Deteriorating Marine Environment, Center for California Public Affairs. Claremont (1972), at 3.

visible from the shore, can have a negative visual impact. In the past, it has been difficult to assess the economic impact of offshore oil platform and drilling rigs on land values. As the Western Oil & Gas Association states, "One resident may compare platforms to warts on ocean surfaces while another may find the harbor view more interesting due to night lights on an otherwise dark horizon.[180] A case-history of the Santa Barbara area is useful to illuminate the problem. Platforms are an "unnatural condition"[181] in the Santa Barbara environment and their visibility to local residents has been the source of much concern as it relates to diminution of land value. The City of Santa Barbara is located in such a manner that approximately 50% of all potential residential property has some view of the ocean.[182] Though some residential properties are a considerable distance from the water, rigs are still visible, even more so, as the dark structure contrasts with the normally light grey-blue ocean.[183] On days of

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79 Draft E.I.S., supra n. 153, at Vol. I p 23.

.80 Wilcox, Susan M. and Walter J. Head, Impact on Offshore Oil Production on Santa Barbara County, California, Wilcox Study, NOAA, Office of C. Grant, Department of Commerce (February, 1973), at 286. Hereinafter cited to as Wilcox Study.

.81 Id. at 289.

.82 Wilcox Study, supra n. 180 at 290.

.83 Id. at 290.

unlimited visibility, some portions of a 100 foot structure, if located 17 miles or less from shore, can be seen from the beach.[184] The negative visual pollution of oil platforms and rigs has been one of many factors adversely affecting land values in Santa Barbara.[185]

Land values also diminish as a result of oil spills. Oil spills contribute to reduction in beach use, both by local residents and tourists, and cause loss of revenue to state and local governments. Tourist expenditures are diverted to activities outside of local areas.[186] Oil spills are said to affect tourists by reducing the physical utility (enjoyment) derived from a beach visit due to oil deposited initially on the beach and ultimately on the feet, clothing and bodies of tourists.[187] As a result of a 1969 spill, Santa Barbara experienced a substantial loss ($3,600,000.00) in tourism.[188] A suit was brought by motel and apartment concerns

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184 Draft E.I.S., supra n. 153, at Vol. II p. 214.

185 Narrative statement of George Hamilton Jones, in the case State of California v. Union Oil Company, et al., filed in the United States District Court Central District of California, Civil Action No. 69-1068-RM, at 21. Hereinafter referred to as the Jones Affidavit.

186 Wilcox Study, supra n. 180, at 284. See also Mead, Walter J., Phillip E. Sorensen, and Kenneth J. Saulter, The Santa Barbara Oil Spills; an Economic Appraisal (1973), at 75.

187 Wilcox Study, supra n. 180, at 283.

188 Id. at 284.

against oil companies for compensation for losses to these businesses during the spill.[189] The suit was settled for $1,050,000. Coastal land owned by private citizens also diminished in fair market value from the spill.[190]

Floating material, debris or oil, that is cast up on the beach or washed into the bay, constitutes an impact on aesthetic value for users or owners of local areas.[191] In addition, construction of onshore facilities needed to support offshore drilling activity cause noise pollution as a result of vehicular traffic to and from these facilities. Noise results from pumping stations.[192] The E.I.S. acknowledges that "there will be an adverse impact upon aesthetic scenic values resulting from construction of onshore terminals, product storage facilities, and pumping stations if these facilities are located in an area valued for its natural or scenic quality."[193] The Western Oil & Gas Association estimates that costs resulting from property damage as a consequence of unattractive aesthetics is approximately 100 to 200 million dollars. The Western Oil & Gas Association admits:

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189 Id. at 284.

190 Jones Affidavit, supra n. 185, at 15.

191 Draft E.I.S., supra n. 153, at Vol. II p. 214.

192 Id. at Vol. II. p. 215.

193 Id. at Vol. II. p. 215.

> There are some instances where communities situated in or about oil production have deteriorated. Examples include Wilmington, Huntington Beach, and Venice. Although oil production may be one of the contributing factors to this decay, it is not necessarily the only one that many of these localities are affected by other types of heavy industry. It is true that oil production in the community of Venice caused serious problems and is probably responsible for the decline that swept through the Venice Peninsula commencing in 1930. (emphasis added) At the same time it must be recognized that operations such as those in Venice are no longer permitted in the City of Los Angeles and are not representative of modern development drilling as conducted by the oil industry.[194]

Unfortunately, a recent appraisal indicates that property values are continuing to be adversely affected by O.C.S. activity. That appraisal, and its background, methodology and findings, are discussed below in considerable detail.

1. Introduction

On January 29, 1979, large quantities of oil and gas began flowing from the ocean beneath or near an offshore drill site situated in Santa Barbara Channel. As a result of this uncontrolled flow, an immense oil slick covered a wide area of the surface of the ocean and was carried to the shores and beaches of the Southern California coastline.

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194 Statements made by Seashore Environmental Alliance with Comments by Western Oil & Gas Association, at 7.

George H. Jones, an independent appraiser, was retained to measure the effect of the spill on the fair market of certain public lands belonging to the State of California, the County of Santa Barbara, the City of Santa Barbara, and the City of Carpinteria. Two dates were chosen to make this value comparison: one prior to the oil spill, January 27, 1969, and the other subsequent thereto, September, 1974. An appraisal was also made of the adverse affect on the utility and/or rental value of these public properties.

Four opinions are expressed for each property considered by Jones:

a. Fair market value, January 27, 1969: an opinion of the value of the properties prior to the beginning of oil spills on January 28, 1969.

b. Fair market value, September, 1974: the fair market value of the properties as of a date subsequent to the oil spill. Jones' appraisal excludes the effect of any physical changes since the earlier date (1969). For purposes of Jones' appraisal, cleanup and other correction of physical damage to the property caused by the oil spill were assumed to have been completed in a proper manner and at no expense to the owner, leaving the property physically equally to its before-spill condition. However, that assumption was made for his appraisal only and was not

intended to imply that such corrective measures had actually been done.

c. Diminution of fair market value due to oil spill: the appraiser's opinion expressed as the difference in value between January 29, 1969 and the second date of value (September, 1974). Other losses in value, if any, accruing to the property by reason of changed economic or other conditions were excluded.

d. Loss in utility/rental value: an opinion of loss in utility arising from the spill from January 28, 1969 to September, 1974. This estimate may also be considered as a loss of effective rental value.

Fair market value is that price, expressed in terms of cash equivalency, which a property will bring if exposed for sale in the open market allowing a reasonable time in which to find a purchaser who buys with knowledge of all the uses and purposes to which it is adaptable and for which it is capable of being used. Neither seller nor buyer is considered to be under any undue compulsion to sell or buy. While public lands are not normally bought and sold in the open market, in Jones' appraisal such land has been measured by the fair market value of equivalent substitute property.

A definition of utility/rental value is the measure of usefulness or desirability of a property expressed in a monetary sum over a certain period of time. It can be equivalent to a fair

rental value, or, in properties not normally rented such as public lands, equivalent to the effective cost of ownership. Fair rental value is defined as that sum which is reasonably expected for the agreed use of the property. Both owner and tenant are considered to be well informed as to the property's physical condition and as to all uses and purposes to which it is adaptable. Neither are acting under any undue compulsion.

2. Methodology

(a) Diminution of Fair Market Value Due to Oil Spill: Uplands and Tidelands

Jones gave greatest weight to before-and-after-spill property sales. Care was taken to exclude the effect of changes in value arising from factors other than those related to the oil spill.

Aside from sales data involving comparable property, consideration was given to market activity of property along the Santa Barbara-Ventura County coastline which, although not directly comparable, would and did reflect seller and buyer reactions to the oil spill. Additional assistance in this analysis was obtained from a study made of market trends existent on beachfront lands in counties both north and south of subject area.

(b) Loss in Utility/Rental Values

Jones' investigation revealed that coastline properties within the study area experienced a general reduction in the utility

rental value following, and due to the oil spill. The utility-rental loss was shown in the pattern and nature of rental history, cancellation of previous rental reservations, increased vacancy factors, rental adjustment required to retain tenancy, etc..

The experience of affected coastline properties was tested against other similar beachfront properties situated outside the oil spill area. Analysis was also made of the pattern of income generated from use and tenancy of facilities within and adjacent to Santa Barbara harbor during the study period. Data was also obtained from the State Department of Parks and Recreation covering the attendance at local and state beach parks before and after the spill.

Applicable data was converted to a calendar year basis to compare with the term of the utility loss. Loss of utility accruing to property from the oil spill was established through analysis of this data. The appraisal was further expanded by comparison of attendance at state beach parks situated in other counties outside the oil spill influence.

(c) Conversion to Monetary Equivalency

Rental and utility losses suffered by income-producing harbor properties was obtained from an anlysis of actual income history. Because parks and tidelands are not generally operated on a lease basis, however, another method of conversion to monetary equivalency had to be developed.

Utility and rental value were converted to monetary equivalency on a cost-of-ownership basis. The state, city or county all had an effective investment in beach properties equal to their fair market value. A major part of the cost of ownership is the interest charge on the investment in, or value of, land and improvements, plus provisions for recapturing the value of improvements over the term of their useful life (amortization).

In some instances, entrance, camping and other fees are charged to visitors and some income is derived from concessions. The operating costs for public lands, however, are far in excess of revenues received. Therefore, the actual cost of ownership results in an additional sum added to that of interest and amortization charges alone. Total annual cost of the facility to the owner must include interest returned, amortization provisions, and the residual operating cost over concession and entrance fee income.

The cost per visitor per year can be developed from the beach park attendance. The utility of a park can be measured, at least in part, by per visitor cost. If a catastrophe occurs, making a park less attractive or of less utility to the public, fewer visitors frequent the facility. Although revenues drop, operating costs would remain approximately the same and interest and amortization charges would remain constant as the owner's investment is not altered. Net cost of ownership per visitor would, therefore, increase. The loss in utility, then, can be measured by the increased cost of serving the public.

Jones utilized the theory of utility or rent loss described above in the analysis of upland properties. Computations for each property vary by reason of differing physical value, operational and attendant characteristics.

(d) Tideland Beach Utility/Rent Loss

The loss in utility-rental value to tideland beaches has been measured in the same manner. The equivalent rental value was adjusted for restricted uses and the nature and quality of beaches and the density of use as reflected in the experience of state beach parks where attendance data is available.

The degree of reduction in attendance at adjacent park areas resulting from the oil spill was then applied to the rent estimate. The term of loss (one to five years plus) is judged also in relation to the experience of the parks in the particular region.

(e) Other Factors Considered

Additional factors considered are summarized below: (a) loss of anticipated future benefits of ownership such as enjoyment of amenities, utilities, pride of ownership, ability to rent or sell and other benefits; (b) impairment of property uses and other amenities which motivated purchase or lease of beachfront or harbor property; (c) market analysis of sales and rental studies, review of opinions and statements of owners, sellers, buyers,

tenants, brokers, and other informed persons; (d) the character of the typical buyer, tenant or user, as to his or her sensitivity to impairment of amenities and ability to purchase, rent or attend some other segment of the California coastline free of the oil spill influence; (e) change in attitude toward amenities of ocean-front property and stability of property as an investment; (f) depth of market demand as compared with other similar areas out-side oil spill influence as well as subject area prior to spill; (g) general uncertainity by owners, tenants, and users as to future oil spills from the same source; (h) effect of continued existence of platforms as a visible reminder of exposure to future oil spil-lage; (i) the widespread awareness of the oil spill and its effects on the local, regional and national market; (j) investors' atti-tude toward effect on rental value and rate of return required to offset additional risks of future rent losses; (k) extent and effect of 1969 spill properties in study area; (l) nature of the property interest being valued; (m) general and local economic conditions; (n) population trends and their relation to beach usage inside and outside the areas of oil spill influence; and (o) personal experience in evaluation of beachfront property along the southern and central California coast since 1948.

3. <u>Findings</u>

Below are Jones' preliminary findings regarding dimin-ution in value and loss in rental/utility accruing to various proper-ties being valued. These preliminary opinions are expressed solely

for the purpose of indicating the general scope of the damage estimates.

PRELIMINARY OPINION VALUE DIMINUTION AND RENT/UTILITY LOSS

State Ownership:

Property	Range of Damages
McGrath	$ 300,000 - $ 450,000
Buenaventura	1,250,000 - 1,500,000
Emma Wood	250,000 - 350,000
Carpinteria	550,000 - 650,000
El Capitan	60,000 - 125,000
Refugio	40,000 - 65,000
Gaviota	75,000 - 100,000
University of California	150,000 - 200,000
Tidelands	1,175,000 - 1,715,000
Total State:	3,850,000 - $5,155,000

County of Santa Barbara:

Property	Range of Damages
Rincon	$ 15,000 - $ 20,000
Lookout	20,000 - 30,000
Arroyo Burro	50,000 - 75,000
Goleta	100,000 - 130,000
Isla Vista	5,000 - 6,000
County Tidelands	50,000 - 65,000
Total County:	$ 234,000 - $ 326,000

(continued)

City of Santa Barbara:

Property	Range of Damages
East Beach-Palm Park	$1,100,000 - $ 1,350,000
West Beach	260,000 - 310,000
Leadbetter	625,000 - 675,000
Shoreline	120,000 - 160,000
Cliff	11,000 - 13,000
Harbor Area	220,000 - 300,000
City Tidelands	250,000 - 365,000
Total City:	$2,586,000 - $ 3,173,000

City of Carpinteria:

City Beach	$ 100,000 - $ 125,000
City Tidelands	115,000 - 155,000
Total City:	$ 215,000 - $ 280,000

TOTAL DIMINUTION AND LOSS IN RENTAL/UTILITY ACCRUING STATE, COUNTY AND LOCAL PROPERTIES

STATE:	$3,850,000.	to	$5,155,000.
COUNTY:	234,000.	to	326,000.
CITY:	2,801,000	to	3,453,000.
	$6,885.000.		$8,934,000.

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195 Jones Affidavit, supra n. 185, at 22.

The purpose of presenting a summary of the Santa Barbara experience as to diminution of land values is to dramatize an important issue which has received scant attention in the E.I.S. We suggest that a careful study and analysis of the general impact of O.C.S. development on coastal land values be prepared prior to O.C.S. leasing.

O. Lack of compensation to local government for losses associated with O. C. S. development

This section attempts to articulate and delineate the issues surrounding the assumption of liability for costs to state and local governments and to the private sector which heretofore have remained largely uncompensated.

The history of industrial development in the United States has been characterized by a laissez-faire attitude which leads to the exploitation of natural resources which are, in fact, nationally owned. Although exploitation has led to detrimental effects upon the surrounding environment, as well as depletion of natural resources, the industrial concern which produces these detrimental effects has not assumed the additional burden of paying for the harm. Growing awareness of the local financial impact of O.C.S development suggests that this attitude should be reconsidered.

The draft E.I.S. does not contain such an analysis. Discussion of the problem, however, is essential to a fully-reasoned understanding of the issues surrounding O.C.S development and a fair distribution of its benefits and costs.

The discussion here will focus primarily on the concept of "externalities." Externalities are costs which are produced by economic or other activities which may or may not have been included in the calculation costs that precede, accompany, or follow production. The thrust of much modern judicial economic

and sociological concern is the more effective industrial or governmental internalization of externalities which heretofore have fallen upon society with no adequate compensation and resulting in a totally inequitable allocation of certain burdens. The discussion of a more equitable assumption of costs for externalities will center on the external costs now borne by state governments, local governments, and private individuals--a crucial focus for a program designed to analyze the effects of proposed O.C.S. development because revenues now paid by oil producers drilling on federal offshore lands go only to the federal government.

A recent report from a Governor's committee in Louisiana[196] discusses equitable sharing of O.C.S. benefits among all levels of affected government. The Report states:

> . . . Although corporations engaged in O.C.S. activity must pay bonuses and royalties to the federal government, these benefits are not automatically shared with that state where the demand for state and local governmental facilities and services from local governments is made more severe by the inability to reach all of those responsible for the increased costs.

The Gulf South Report will act as a statistical and practical basis for the following discussion of efficient and equitable internalization of these externalities. The theoretical basis for the following discussion is based on an insightful and illuminating

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196 Gulf South Research Institute, Baton Rouge, Louisiana, Offshore Revenue Sharing: An analysis of Offshore Operations on Coastal States, prepared for the Governor's Offshore Operations on Coastal States, GSRI Project No. X5-614 at 1. (hereinafter cited to as Gulf South Report.

law review note entitled A Decision-Making Process for the California Coastal Zone.[197] This article proposes that all affected parties become viable participants in the decision-making process which affects development of both private and public resources. The underlying framework for the argument advocating a totality of participation is described as follows:

> . . . the appropriate social arrangement for an optimum allocation of resources should be a result of an examination of and choice between alternative real institutional systems - i.e. institutional systems operating not merely in "theory", but in a society where decisions in both the public and private sectors are reached by bargaining among interested persons, where persons affected by decisions arising out of the bargaining process are often not represented in that process, and where decisions in both the public and private sectors are reached with limited information about the desirability of alternative decisions.[198]
> (Emphasis added.)

Considering the problem of externalities from both a theoretical and an empirical foundation, we recommend that the Department of the Interior review the current distribution of benefits and burdens, and consider the implementation of an equitable revenue-sharing system between the federal government and other affected bodies, both governmental and private, or,

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[197] Southern California Law Review, A Decision-Making Process for the California Coastal Zone, Vol.46, No. 2 (1973), at 513-564. (hereinafter cited as A Decision-Making Process.

[198] Id. at 515.

alternatively, institute a judicial or administrative scheme for the imposition of development charges[199] upon the oil producers granted the privilege of O.C.S. development.

1. A Theoretical Argument in Favor of Institution Methods to Effectively Internalize Externalities

Although A Decision-Making Process is specifically oriented towards an economic and legal analysis of the problems of effectuating efficient management of the California Coastal Zone, the analysis applies equally well to any discussion of the utilization of public resources. O.C.S. development inevitably will cause many obvious externalities. This eventuality should be considered now by B.L.M. in order to prevent ongoing and future litigation and other problems arising from these costs.

As general background the conceptual framework of A Decision-Making Process should be delineated. The author articulates the difference between a "comparative" approach to the issues of externality control and an "absolutist" or "nirvana" approach. The latter approach leads to a polarity of positions and is usually not helpful to a successful resolution of the issues. The former tends to balance the conflicting positions and attempts some practical compromise. A longer exposition of this point is contained in Demsetz, Information and Efficiency: Another Viewpoint, 12 J. Law and Econ. 1, 1 (1969) which states:

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199 Id. at 551-564. See generally the final arguments and conclusion of the note where the recommendation is strongly made for the imposition of development charges in the coastal zone context.

> . . . The "nirvana" approach implicitly presents the alternatives to any allocational problem as the present "imperfect" institutional system and some ideal norm. Its advocates seek discrepancies between the real and the ideal. Once discrepancies are found, it is deduced that the real is inefficient and insufficient. On the other hand, a comparative institutional approach uses the ideal only as a standard to measure divergence between alternative real institutional arrangements in a process of selection of the arrangement most able to cope effectively with the problem.[200]

We suggest that the B.L.M. take a comparative institutional approach in its analysis of these problems in order to preserve what institutional efficiency and equity already exists and to modify the institutional methods to incorporate more effective means of spreading these costs.

The claim for effective internalization of externalities is grounded in discussions involving the decision-making process itself. It is essential to equitable decision-making that there be effective participation of all interested parties. A Decision-Making Process describes the unfortunate consequences to the general welfare when effective participation has not taken place:

> When a decision-maker fails to consider the effects of his decisions upon others, the costs which he calculates as incidental to alternative allocations of resources are not equivalent to the costs that society will incur as a result of his decision. Thus, a divergence between social and private costs (or benefits) will result, and the price mechanism will not serve as a check on his decisions to insure that his interests coincide with those of society. The Pigouvian[201] tradition asserts that, when such a

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200 Id. at 514-515.

201 Id. at 517.

> divergence exists, steps should be taken to equalize private and social costs through taxation or subsidization.[202]

Because inequitable results can have a dire impact on public attitudes, the economy and the general welfare, emphasis should be placed upon improving the decision-making process. The existence of substantial externalities shall generate the necessity for methods encouraging wider participation and encourage the public sector to seek more effective participation:

> . . . the general solution to the problem of externalities is to expand the scale of decision-making so that additional participants have an input into the bargaining process. This will insure that all competing demands for resource use will be considered in allocational decisions, and that an individual acting in his own best interest is acting in society's best interest as well. It appears, therefore, that the existence of externalities creates an incentive (analogous to the concept of market demand) for altering the process through which decisions are made.[203]

Although there has been substantial academic discussion and empirical implementation of changes in the decision-making process to accomodate the private sector, such a process is only beginning to emerge for the public sector.

In considering costs produced by economic development, weight should be given to factors involving "fairness" as well as those involving "efficiency". Until the present time most economic

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202 Pigou, A., THE ECONOMICS OF WELFARE, 4th Ed. (1932).

203 A Decision-Making Process, supra n. 197, at 518.

developments have focused almost entirely on efficiency matters.[204] Yet there is a growing interest in the effective incorporation of "fairness" concerns. The importance of the national basis for this shift in emphasis is contained in the following exposition:

> . . . a determination of the optimum social arrangement should involve considerations of fairness as well as the efficient allocation of resources. The value (or cost) of a resource is a function of the expectations of future returns from it. Inequity generally arises in the context of resource allocation when pre-existing expectations are upset, thereby causing a transfer of assets from one resource user (or non-user) to another. The usual remedy for such an unexpected and inequitable transfer of assets is a corresponding payment of compensation. Indeed, these considerations, implicit in the just compensation clause of the Fifth Amendment, may be constitutionally compelled. (Emphasis added.)[205]

Some assert that "fairness" concerns are unimportant because the price mechanism of the market will take into account any additional costs. That argument, however, is negated by the fact that the pricing mechanism does not always work:

> One example of a situation in which externalities are not accounted for in pricing decisions is seen when prior official statements that the public has rights to alter private lands without compensation are not considered in price fully because there has not been enforcement of the "rights" in the past. On the other hand, externalities may put the parties on notice of future restraining action. For example, a purchaser of property in an undeveloped area which is expected to be developed soon will consider in the price paid for the property that certain uses, such as letting his wastes settle upon surrounding land, may be restrained at some future time. (Emphasis added.)[206]

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[204] See generally, Coase, The Problem of Social Cost, 3 J. Law and Econ. 1, (1960).

[205] A Decision-Making Process, supra n. 197, at 530.

[206] Id. at 531.

Just as this future purchaser of property must be made fully aware of the external costs if he develops his land, so must O.C.S. developers realize their liability for future external costs imposed by their development on nearby governments and individuals. That liability must be included in their calculations of the price paid in a lease system. Their calculations must also include the cost of compensating those harmed as a result of external effects.

The insightful analysis contained in The Decision-making Process concludes with an explication of a system of development charges which effectively internalize many externalities that will be produced by developers of the California Coastal Zone. We suggest that the Department of the Interior or B.L.M. consider such methods of efficiently and equitably spreading the cost of O.C.S. development.

2. An Empirical Analysis of the Benefits and Costs of O.C.S. O.C.S. Development Off the Coast of Louisiana

The Gulf South Report, supra, provides a thorough statistical foundation for issues involving the necessity of revenue-sharing processes between federal, state, and local governments. The report summarizes both the benefits and the costs to Louisiana of O.C.S. development:

> The development of petroleum resources from O.C.S. regions produces both economic benefits and costs for adjacent coastal states. One of the major benefits is increased employment and associated incomes for people in the region, while the primary cost of such development stems from the increased

demand for governmental facilities and services. The development of these petroleum resources is of particular concern because the activity is beyond the taxing authority of both state and local governments.[207]

The study not only summarizes in statistical and textual fashion the actual impact on Louisiana of O.C.S. development but also attempts to formulate some of the problems which other states might face as a result of similar O.C.S. development. The document[208] is an invaluable source:

> This study evaluates the impact of O.C.S. activity on state and local governments in contiguous coastal states. The situation in Louisiana is examined in detail in order to determine the cost of governmental services associated with the large amount of activity in the O.C.S. region and to indicate what other coastal states might experience as their O.C.S. regions are developed. This is done in the context of an understanding of the physical relationship of the O.C.S. to the coastal areas, the petroleum potential of various O.C.S. regions, and the national energy crisis.[209]

The Gulf South Report is a justification on statistical grounds for the assertion that the federal government should be compelled to share the proceeds realized from O.C.S. development.[210]

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[207] Gulf South Report, supra n. 196, at 1.

[208] The Gulf South Report is a long and detailed report. The issues it raises can only be discussed above in a summary fashion. However, we commend the full report to the reader for analysis.

[209] Id. at 1-2.

[210] Id. at 4-5. "Although the companies directly involved in O.C.S. production pay large sums to the federal government in the form of bonuses and royalties, these are not shared with the states providing the services and facilities used. There is presently no equivalent sharing of revenues from federal O.C.S. activities as the 37-1/2 percent shared from mining operations on federal lands within

Moreover, the oil producers, arguably, should be administratively compelled to enter into a revenue-sharing scheme with the affected state and local governments in order to provide compensation for the external costs created by their activities which have not been adequately offset by increased benefits to onshore interests.

The Gulf South Report focuses upon the comparative merits of O.C.S. development affecting Louisiana. A brief statement of both the benefits and the costs incurred by O.C.S. development is in order. The primary benefits conferred by O.C.S. development in Louisiana involve an increase in employment opportunities:

> In Louisiana, . . . O.C.S. production directly induces employment in the areas of mining, manufacturing, construction, chemicals production, and refining. These employees, in turn, induce employment in a wide range of service and trade industries. In all, it is estimated that the total employment impact of O.C.S. activities in Louisiana is approximately 124,400 employees. When the families of these workers are included, the population impact is estimated to be approximately 391,000.[211]

Such an increase in population and employment can also be a beneficial impact upon state and local governments in the form of increased consumer activity and alleviation of welfare problems.

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state boundaries. In 1972 approximately $336 million in royalties was paid to the federal government by firms operating beyond the three-mile boundary offshore Louisiana."

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Id. at 517.

The costs of O.C.S. development, however, appear to outweigh the benefits. Briefly, these costs, fully developed by supporting statistical data in the Gulf South Report, can be summarized as follows:

1. Impact of possible oil spills.
2. Impact of developing channels, laying pipelines, building rigs, and disposing of waste materials.
3. Effects of production activities on marsh land, and on fish and wildlife habitats.
4. Loss of land for competing uses.
5. Detrimental effect on the aesthetic appearance of the coastal regions.
6. Impact on individual port facilities and roads.
7. Impact on a myriad of public services including education and police protection.
8. Absence of opportunity for state and local governments to tax these activities because they exist on Federal lands.[212]

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212 *Id.* at 541. "In setting up a tax structure to support the expenditures deemed necessary and desirable in a society, government seldom attempts to draw precise one-for-one relationships between taxes paid and benefits received. For example, persons pay property taxes which are used, in turn, to support education. The taxes are not based on how many children are in a household; rather, it is reasoned that there is a social benefit from having education available for all children. Even in cases where there are more directly traceable benefits between taxes and services, as in the case of highway use taxes, the tax is based on such variables as fuel consumption and weight--neither of which may be directly related to the benefit the user sees in being able to use the highway system. So it is with nearly all taxes. The revenues from a whole array of taxes are needed to finance the nation's collective expenditures."

The Gulf South Report concludes:

> Regardless of the tax or economic structure, however, someone must subsidize the supplying of service to outer continental shelf users relative to what would be the case if taxing powers were present.[213]

Special emphasis is placed upon the large sums that are lost to the state because of the inability to tax O.C.S. development despite the costs associated with providing onshore services. The lost revenues derive from the inapplicability of the following taxes: (1) severance, (2) income, (3) corporate franchise, (4) sales and use, (5) occupational license, (6) ad valorem, and (7) miscellaneous which includes primarily power use taxes and a small amount of natural gas franchise tax.[214] The taxes foregone in all these categories in 1972 are estimated at $183,488,000.

The estimated cost of governmental services arising as a result of O.C.S. activity is $265,044,000.[215] Individuals are paying their appropriate part of these costs but 60 percent of these costs are borne by corporations. Because much corporate activity is taking place on the O.C.S., private corporations are not paying their appropriate share.

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213 Gulf South Report, supra n. 196, at 541.

214 Id. at 555.

215 Id. at 558.

An interesting and somewhat unusual possible future cost of O.C.S. development is expressed as follows:

> In addition to the fact that current offshore operations require shoreline governmental services, there is uncertainty over the future economic base of the area. Much of the expansion of public facilities and services has been based on the rapid growth and needs of the offshore oil and gas operations. However, in 1972 over 38 percent of the offshore area adjacent to Louisiana was already under lease. As to what happens to this area when the oil and gas reserves are depleted, one cannot say. This added uncertainty is a cost to state and local government which cannot be quantified at this time. Nevertheless, the cost must be recognized and steps taken to prevent an Appalachia from developing in the coastal zone.[216]

The Gulf South Report takes caution to point out that there may be significant differences in the costs that will be imposed on other coastal areas if the O.C.S. is developed in other areas. The differential is based on the following rationale:

> These estimates of costs for governmental services are only rough indications of the potential magnitude of such costs. In reality, many factors enter the situation. The cost of governmental service will vary from region to region and probably can be expected to rise for all regions. The employment relationships currently applicable in the Louisiana situation may not hold for other areas now or in the future. Moreover, the productivity of the petroleum fields themselves can be expected to vary from region to region.
>
> In view of all these factors, it is useful to consider the magnitude of the potential costs and to consider the direction of the potential errors in these estimates. Two factors may suggest that the costs can be even higher than

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216 *Id.* at 565.

that estimated. These factors are (1) that the Louisiana offshore fields have been very productive and other regions may experience less productivity; and (2) the costs of governmental services have steadily risen for all regions in the country.[217]

Thus, there is a likelihood of greater costs from O.C.S. development in subsequently-leased areas. For this reason, we suggest that B.L.M. consider such issues now in order to avoid even greater economic imbalance in the future.

3. <u>Substantiation of the Gulf South Report by a Similar Texas Study</u>

At the request of State Senator A.R. Schwartz, a recent study was published on November 20, 1974[218] entitled <u>Benefits and Costs to State and Local Governments in Texas Resulting from Offshore Petroleum Leases on Federal Lands</u>. The study made these conclusions:

1. Increased annual revenues to State and local government will be $48.9 million. (There is no direct tax or other direct income to the adjacent state from production on federal offshore lands; thus, these revenues are taxes collected on related expenditures that are made within the state.)

2. Cost of additional services that will have to be provided by State and local government are estimated at $111 million per year.

3. Thus, the NET COST to State and local government, in excess of benefits, will be $62.1 million per year.[219]

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217 <u>Id</u>. at 569-70.

218 Office of Information Services, Governor's Office, Austin

The body of the report sets out the statistical and diagrammatic analyses supporting the conclusions above. Most of the data tends to support the findings of Gulf South Report.

In Texas, the estimated growth in total employment is 69,034. This will result in a total population growth of 177, 961. A comparison is made between the benefits conferred on the State of Texas by O.C.S. development through this increase in employment and population and the burdens imposed on Texas primarily through the provision of increased public services.[220] The report concludes:

> Therefore, given the current tax structure and level of public service expenditures, production of the offshore leases would not result in an improvement in the fiscal condition of state and local governments in Texas. The cost to Texas state and local government associated with production of the federal leases are estimated to exceed the associated benefits by $62.1 million, annually.[221]

A critique of this Texas study was issued in an informal manner by Mr. William Ahern of the Rand Corporation in Santa Monica, California.[222] Mr. Ahern criticizes many of the components of the Texas study:

1. There appears to be a strong bias in favor of Texas acquiring a much-larger percentage of the

218 cont'd: Texas, Benefits and Costs to State and Local Governments in Texas Resulting From Offshore Petroleum Leases on Federal Lands, prepared at the request of State Senator A.R. "Babe" Schwartz (Nov. 14, 1974). Hereinafter cited as The Texas Study.

219 Id. at 29.

220 Id. at 8.

221 Id. at 8.

222 Letter from William Ahern (Rand Corporation) to Mr. Peter Douglas, Consultant, Assembly Select Committee on Coastal Zone Resources, State Capitol, Sacramento, California, December 9, 1974.

federal funds realized from O.C.S. development rather than participating on an equal basis with other states in a national revenue-sharing scheme through the Land and Water Conservation Fund which distributes federal funds to federal and state park agencies for acquisition of parkland. These funds arise from payments to the Federal government from O.C.S. development.

2. The Texas taxing procedure appears to place heavier burdens on oil consumers in other states since its major revenue-producing tax, and the reason that Texas does not have a state income tax, is a severance tax on oil produced in the state.

3. Mr. Ahern believes that The Texas Study has greatly overestimated the increase in employment as a result of O.C.S. development.

4. Mr. Ahern believes that the statements from The Texas Study involving governmental costs do not include federal contributions which have already been applied to mitigate these costs.

These criticism of the Texas Study notwithstanding, Mr. Ahern states that this question should be addressed in California and "I'd love to do the job right for the State of California." These latter statements support the general tenor of Mr. Ahern's letter which is not that he believes the findings of the Texas study regarding the problems of fair assumption of

external costs and equitable revenue-sharing schemes to be wrong, but rather that some of their methods might be questioned on grounds of statistical accuracy.

Mr. Ahern also expresses his interest in California problems specifically: "1) In terms of California's benefit, it is not beneficial to have Texas share a greater portion of funds if that means we would have much less parkland in [California]. 2) The taxing discussion is not relevant to California because California has sales, property, and importantly, income taxes which offset public service costs."

The critical point is that neither party denies the fact that the questions involving equitable-sharing are important and deserve thorough investigation.

D. Conclusion

The preceding discussion addresses crucial economic questions: What are the external costs created by O.C.S. development? Are these costs being borne in an economical and equitable manner? How could these costs be more effectively allocated? Who should bear these costs in the future? The Department of the Interior did not address these questions in the draft E.I.S., despite their importance to the economy of coastal states. No compensation is being paid to states, local governments, and private individuals for costs incurred as a result of O.C.S. development even though agreement has been made to assume these costs.

We recommend that the Department of the Interior undertake to study the problem of equitable sharing of costs and to formulate rational institutional approaches to resolve the problem.

IV AN ECONOMIC ANALYSIS OF THE FEDERAL LEASING SYSTEM

The purpose of N.E.P.A. is to assure that environmental values be given appropriate consideration in decisionmaking along with economic and technical consideration . . ." 42 U.S.C. §102(2) (b). (emphasis added) For this E.I.S. to be a comprehensive cost-benefit analysis, the E.I.S. must explore the economics of the leasing system. In determining whether the adverse environmental impacts of O.C.S. development are outweighed by the need for the petroleum and the economic value of leasing, there must be a careful analysis of the issue of whether the nation is receiving a fair return for use of national resources belonging to all of the people.

There are serious deficiencies in federal O.C.S. leasing practices. Economic analysis of those practices reveals that the current "bonus royalty" procedure for leasing federal lands on the O.C.S. does not encourage effective bidding competition, does not guarantee a fair return on the value of leased federal lands, and does not encourage the optimum rate of development of oil and gas reservoirs.

These deficiencies indicate the need for an evaluation of alternative leasing procedures. The draft E.I.S., however, dose not consider the relative economic merits of other leasing methods. Only the current leasing system is seriously considered. Given the importance of choosing the leasing procedure which will produce the greatest return to the federal government for this valuable property, we recommend that B.L.M. officials make a thorough appraisal of alternative leasing procedures in light of available economic data before undertaking the proposed O.C.S. development.

In evaluating the economic merits of various leasing methods, several factors should be considered. A leasing procedure should be chosen with an eye toward the future value of oil lands as well as to an accurate evaluation of the present high value of this resource. U.S.G.S. should be provided with sufficient guidelines to guarantee an accurate ongoing appraisal of the value of the oil produced throughout the term of the lease. As well as acting as a safeguard for a fair return from the federal offshore lands, U.S.G.S. must be afforded adequate guidelines and standards in order to effectively supervise the exploitation of oil lands by producers. In this regard, primary emphasis must be placed upon supervising the rate as well as the methods of exploitation used by the oil producers.

We recommend that the Department of the Interior and the federal government give serious consideration to the following: (1) alter the current form of leasing, (2) emphasize fair market return to the federal government, (3) share the risk of exploration and development of the resources, and (5) pursue the investigation of other energy sources through contributory funds from offshore oil development.[223]

A. Current Leasing Procedures

1. <u>What is the Leasing System at Present?</u>

Most O.C.S. leases to date have been granted according to the "cash bonus-fixed royalty" system, pursuant to the following statutory language of 43 U.S.C. §1337 (Outer Continental Shelf Lands Act):

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The primary research document which served as the foundation for the following argument and analysis is a report prepared by the Office of Energy Research and Development Policy, National Science Foundation, prepared in September, 1974, entitled, <u>An Economic Analysis of Alternative Outer Continental Shelf Petroleum Leasing Policies</u> 'hereinafter referred to as the National Science Foundation Report

> The bidding shall be . . . (2) at the discretion of the Secretary, on the basis of a cash bonus with a royalty fixed by the Secretary at not less than 12 1/2 per centum in amount or value of the production saved, removed or sold, or on the basis of royalty, but at not less than the per centum above mentioned, with a cash bonus fixed by the Secretary.

The only exception to this system of bidding (although the statute does provide for the implementation of alternative bidding systems) is the proposed leasing of O.C.S. lands off the Louisiana coastline where an experimentation with the "royalty-fixed cash bonus" system is included in the total leasing scheme:

> All O.C.S. lease sales to date have been conducted on a cash bonus, fixed royalty (16 2/3%) basis, although imminent Louisiana #36 includes 10 tracts being offered on a royalty basis as a test of that system.[224]

The cash bonus fixed royalty system operates as follows:

> The salient features of current leasing policy are: determination of the lessee by "bonus" bidding; establishment of the royalty rate at one-sixth of the wellhead value of petroleum; exploration and tract nomination by private industry; and limited acreage leased annually by the government.[225]

This system combines an opportunity for oil producers to offer, on a competitive basis, an initial substantial cash payment, which will be paid to the federal government upon granting of the lease, with a fixed royalty established by the Secretary of the Interior based upon the estimated value of the leased lands.

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224 Draft E.I.S., supra n. 131, at Vol.I p 93.

225 National Science Foundation Report, supra n. 223, at 1.

The current economic situation, however, is vastly different from that existing at the time the system originated. The primary economic changes which have occurred in these areas are: (1) a switch from private to public lands as the target of oil exploration; (2) greater costs of drilling; (3) a rise in price of oil; (4) greater market and environmental uncertainties; and (5) a greater reliance on O.C.S. resources.[226]

The historical precedent of the development of private lands made it economically desirable to place the risk of development solely upon the oil producers, as small landowners did not possess the resources to assume this risk. That rationale is no longer operable in the context of O.C.S. development because the landowner is the federal government. The government as lessor can easily share the risk in exchange for a greater part of the return on its resources.

Proponents of the present system may argue that it is better for national security if the risk of investment continues to be borne by the private sector. That argument assumes that the federal government should never assume financial risk. To the same extent that a private firm with a large financial base can act as its own insurer with impunity, the same argument holds for the substantial federal reserves.

The risk allocation arguments in this critical area of oil development must be squarely faced. Where a natural resource is largely speculative in its potential and present value, there may be some value in allocating the financial risk of this develop-

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226 <u>Id</u>. at 2.

ment to the private sector, but where the resource is as certain of substantial and rapidly appreciating value as are the oil-producing lands of the O.C.S., the argument seems inappropriate.

2. Problems Inherent in Systemic Structure

Although by statute the bidding procedure to be utilized should be "competitive bidding" (43 U.S.C. §1337), the "cash bonus fixed-royalty" system contains serious deficiencies in theory and in practice which discourage a truly competitive bidding procedure. The major detrimental impact upon competition involves the *de facto* exclusion of independent oil producers from viable participation in the bidding procedure.[227] The exclusion occurs primarily at the outset of the bidding procedure with the requirement of the ability both to bid a substantial cash bonus and to actually pay that huge amount at the time of the lease grant. The requirement of a large initial cash payment is a substantial hardship imposed upon independent producers which effectively diminishes the opportunity for competitive bidding. "Good faith" bidders are in effect limited only to large oil producers with substantial ready capital reserves.

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[227] Committee on Commerce, Outer Continental Shelf Oil and Gas Leasing Off Southern California: Analysis of Issues, request from Senator Tunney, National Ocean Policy Study (Nov., 1974), at 24. Hereinafter cited as National Ocean Policy Study.

The proponents of the present bidding system argue that the initial large payment guarantees the financial stability of the successful bidder. If the concern is truly with a secure financial foundation which will avoid the possibility of subsequent financial disasters, then the focus should be placed upon regulatory limitations on the financial eligibility of competing producers rather than upon the exclusionary device of a large initial payment.

(b) Do the Major Oil Firms Dominate?

According to the National Science Foundation: "While there are numerous small firms in the U.S. petroleum industry, about 20 major, vertically integrated firms dominate the market and participate most actively in O.C.S. lease sales. . . . Historically these few firms have engaged extensively in joint bidding and have exploited other opportunities to share information. Some leasing strategies can increase the likelihood of competition and a fair market return to government-owned resources. Barring the possibility of substantially increasing competition, one must be wary of predicting the outcomes of alternative leasing policies based on models which assume perfect competition." National Science Foundation, Supra at p. 4

3. Problems of Inadequate Government Regulation

In addition to substantially limiting competitive opportunity, the "cash bonus-fixed royalty" system creates potential problems regarding the efficient development of offshore lands

because of the lack of governmental control of the actual exploitation of these lands. All of these potential problems could be substantially mitigated or even eliminated if the Secretary of the Interior pursuant to the authority granted by 43 U.S.C. §1337-1343 exercises his discretion to promulgate stringent regulations regarding the supervision by U.S.G.S. of the actual operating procedures of oil producers as well as the bases upon which the payments of royalties are calculated. Without such regulatory standards, the nation can logically expect that some, if not all, of the following possible inefficiencies will develop.

(a) Is the Rate of Development Too Fast?

The payment of a large sum at the outset of the least grant may encourage inefficient development.[228] It is to the advantage of the successful oil producer to develop the resource as quickly as possible without consideration of long-range efficiency because oil producers are encouraged to seek short-term recoupment of capital investment. From a long-range standpoint, it is also to the oil producer's advantage to develop the resource as

228 Id. at 40. "Effect that the bonus bid system as it presently functions, may have in 'forcing' the development and exploitation of the O.C.S. With the large front end investments required by the bonus bid procedure, it is alleged that the industry is compelled to accelerate its drilling program to recover its investment quickly . . . can lead to hasty ill-conceived developments which may result in environmental damage."

efficiently as possible in order to guarantee a steady, and, indeed, increasing return on investment with the eventual recoupment of the initial outlay.

The latter interpretation appears to be most consistent with efficient business management methods. The possibility of the occurrence of the first interpretation, however, should not be summarily dismissed without thorough consideration of the promulgation of regulatory safeguards which would effectively prohibit rapacious development.

(b) Is The Rate of Development Too Slow?

The payment of a large initial sum and the security of a fixed royalty rate for the term of the lease may permit successful bidders to develop the resource at a slower rate than would be in the national interest. The proponents of this criticism imply that the oil producers would be primarily interested in controlling the input of offshore oil into the supply stream in order to guarantee their own financial advantage. If this view is correct, then the national interest as expressed by the goal of self-sufficiency in Project Independence Blueprint will be substantially threatened, for self-sufficiency depends upon rapid, yet efficient, development of the offshore resources. Regulations affecting U.S.G.S. practices should include safeguards against rates of development based upon the self-interest of oil producers rather than upon stated national goals and policies, and efficient development of our resources.

(c) Are Regulation Procedures Deficient?

Another potential problem arising from the present "cash bonus fixed-royalty" system, and a particularly important one from the viewpoint of the government treasury, is "1980 oil for 1975 prices". Given that the value of oil has substantially appreciated in the last decade and given that the worldwide energy shortage and demand for oil will, in all probablility, continue indefinitely, leased lands arguably will be more valuable in 1980 than at present. In practice there has been no thorough review of the exploitation of the leases and as a result leases are seldom terminated.[229] The automatic renewal effect can be countered by regular U.S.G.S. scrutiny of the development of O.C.S. leases by producers coupled with a review process to determine whether leases should be renewed or terminated.

4. Conclusion

The National Science Foundation has concluded:

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229 Id. at 7.

The historical background . . . documents the limited development of leasing policy over the past two decades in sharp contrast with the dramatic changes in economic conditions and social objectives. Specifically past leasing strategies have not been changed in response to increased petroleum prices and development costs or to the increased geologic uncertainty associated with greater reliance on and acceleration of leasing on the O.C.S. In addition, society is considerably more conscious of environmental protection concerns than when leasing policy was established. Moreover, the recent 'energy crisis' has substantially renewed concern with issues of market power in the petroleum industry and with the adequacy and optimal allocation over time of resources. National Science Foundation, Supra, at p.6

The argument above substantiates the need for the Department of the Interior to undertake an in-depth study of the economic[230] and environmental merits of the present leasing procedure. Such an investigation would reveal the problems inherent in continued reliance upon the bonus royalty system for future O.C.S. development and suggest numerous reasons to accept one of the leasing procedures outlined below.

B. Alternative Leasing Systems

Total discretion for the choice of a leasing system resides in the Secretary of the Interior:

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230 The Accelerated Development of the Outer Continental Shelf: Its Problems and Costs, prepared for the Ad Hoc Committee on the Domestic and International Monetary Banking and Currency Committees of the House of Representatives (Dec., 1974). See generally Chapter 5. Hereinafter cited as the Banking and Currency Report.

"Congress gave the Secretary of the Interior little guidance on the objectives of O.C.S. leasing. The O.C.S. is to be leased 'in order to meet the urgent need for exploration and development,' but the rate of leasing and even guidelines as to how to measure the need are completely unspecified. Bidding may either be on the basis of a fixed royalty and cash payment (lease bonus)--the method used to date--or on the basis of a fixed cash payment and royalty bid--a method which began on an experimental basis in 1974 in Louisiana. In either case, the royalty must be greater than 12 1/2 percent. Sealed bidding and the maximum size and term of the lease are specified, but the Secretary of the Interior is entitled to prescribe any other terms and provisions deemed appropriate prior to offering an area for lease." [231]

The draft E.I.S. contains a brief discussion[232] of only three alternative leasing systems. These alternatives are: (1) royalty bidding with fixed bonus; (2) net profit sharing; and (3) deferred bonuses. The E.I.S. discussion lacks sufficient economic analysis of the other leasing systems considered to render any of them viable economic alternatives to the present leasing method. Inadequate consideration of alternative leasing systems results in an unreasoned reliance upon the current system.

The National Science Foundation Report, on the other hand, contains a comprehensive analysis of ten alternative leasing schemes. The ten alternatives are grouped for analytical convenience under the three general headings of (1) royalty schemes, (2) rental schemes, and (3) profit-sharing schemes.

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231 National Ocean Policy Study, supra n. 227, at 10.

232 Draft E.I.S., supra n. 131, at Vol.II pp. 414-418.

The four royalty schemes are:

1. Fixed royalty/bonus bidding
2. Fixed bonus/royalty bidding
3. Royalty schedule decreasing over time
4. Two-parameter royalty schedule

The four rental schemes are:

5. Rental payments/bonus bidding
6. Fixed bonus/rental bidding
7. Oil pledge/bonus bidding
8. Fixed bonus/oil pledge bidding

The two profit-sharing schemes are:

9. Fixed profit share/bonus bidding
10. Fixed bonus/profit share bidding

Compared to the National Science Foundation treatment of alternative leasing procedures, the draft E.I.S. treatment of the subject is wholly inadequate. We suggest that the Department of the Interior should institute an independent comprehensive survey and analysis of all available expert materials and personnel on the issue of leasing procedures. Until these alternatives have been adequately considered and discussed in the final E.I.S., we suggest that the B.L.M. proceed no further with the leasing process.

We will proceed with a discussion of the general considerations underlying the various royalty schemes because clear statutory authority exists for the immediate implementation of these alternatives. Rental and profit sharing schemes are discussed only briefly. We focus on alternative lease systems here

because there is a very short period of time available to the B.L.M. to seriously consider implementation of an alternative bidding scheme before drafting the final E.I.S.

1. <u>What Are The Alternative Royalty Systems</u>?

The statutory authority for alternative royalty systems is as follows:

> The bidding shall . . . (2) at the discretion of the Secretary, . . . or on the basis of royalty, but at not less than the per centum above mentioned, with a cash bonus fixed by the Secretary. 43 U.S.C. §1337.

The draft E.I.S. description of royalties is as follows:

> Under royalty bidding leases would be awarded to the firm that pledged to the Government the highest percentage of future production for an individual tract. Therefore, the bulk of federal revenues would accrue from royalty payments made if and when production occurred.[233]

Risk under a royalty system is allocated as follows:

> For the leaseholder this means that government payments--aside from a nominal fixed cash bonus--depend on production. If the leased property is not productive, payments to the government are not made. <u>Royalty bidding thus means that the risk of an O.C.S. enterprise is shared by both the government and the leaseholder</u>. (emphasis added)[234]

The National Science Foundation Report recommends the following in regard to royalties:

> . . . If royalties are to be the principal means whereby the government shares risk with firms, we suggest the following:

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233 <u>Draft E.I.S.</u>, <u>supra</u> n. 131, at Vol.II p 414.

234 <u>Id</u>. at Vol.II p. 414.

A. Riskier areas should carry higher royalties or, better, should incorporate a two-parameter royalty system. The two-parameter system shares risk more effectively without increasing the 'no development' hazard. Royalties should be the same within fields but need not be the same for different fields.

B. Royalties should decline through time to reduce early shutdown problems. Initial royalties might be made higher to keep bonus bids at desireably low levels.

C. A fraction of costs associated with exploration and development after leasing should be deductible from royalties. If royalties are r percent, the amount deductible should be r percent of exploration and development costs. Otherwise, there will be underexploration and development on leases with consequent loss of production and government revenues.[235]

The only O.C.S. lease to be granted on the basis of a royalty system is a prospective lease to be included in the O.C.S. grant in Louisiana. That test sale is described as follows:

> This particular sale is the first in which bidding for leases on a royalty basis will be conducted on a test basis. The O.C.S. Lands Act provides the Secretary of the Interior with discretionary authority to issue leases on the O.C.S. to the highest bidder either on a cash bonus basis with a fixed royalty or on a royalty basis with a fixed cash bonus. The purpose of the test is to determine what the effect of royalty bidding for O.C.S. leases will have on Federal revenues, competition and the rate of production on individual leases.[236]

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235 National Science Foundation, supra n. 223 at 35.

236 Draft E.I.S. (Vol. 1 of 2), 1974 O.C.S. Oil and Gas General Lease Sale Offshore Louisiana at 8. Hereinafter O.C.S. Oil & Gas Louisiana.

The specific tracts chosen for the test of the royalty system were selected in this manner:

> Of the 295 tracts chosen for this sale, 10 tracts were selected for the royalty bidding test from 10 different trapped hydrocarbon structures. These structures were chosen randomly within the criteria that the structures were to have promising oil and gas potential and that there were to be no tracts under lease on the structure. From the 10 structures, one tract per structure was chosen at random. [237]

What, then, are the comparative merits of the cash bonus and royalty systems? Relying on the data produced by this test sale, the B.L.M., which is the agency within the Department of the Interior with the authority to call and to issue leases, soon will have a comparative numerical basis to justify the agency choice of either of the two previously discussed leasing systems. The data will be extremely important for providing a statistical foundation for the choice of future leasing schemes.

An important economic difference between the two leasing systems is that in a royalty scheme the federal government would not reap the initial benefit of a large cash bonus payment. Such a large immediate payment would help bolster present federal budgetary deficiencies. However, in following a royalty scheme, the federal government may, in fact, reap greater total monetary benefits over the lifetime of the lease because of the higher percentage rate of royalties.

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[237] Id. at 34.

The assumption of greater return to the federal government over a longer period of time in turn rests upon the belief that the price of oil will continue to rise. That assumption of continued higher prices continues to be the source of learned controversy:

> A royalty is a payment based on a specified fraction of the production of a lease. Royalties are contingent payments in that they are paid only if oil is produced on the lease. Royalty payments also depend upon the current market price of oil and thus share price uncertainties as well as discovery risk. Current legislation requires royalties of at least one-eighth (12 1/2 percent) although O.C.S. leases typically require royalties of one-sixth (16 2/3 percent). [238]

There is adequate current information, however, that would lead to the conclusion that the value of oil is more likely to increase between 1975 and 1980 or, at least, to remain at its presently high level, rather than decrease. The risk to the federal government, therefore, would be rather minimal.

The inordinately rapid rise in oil prices in the last decade, on the other hand, may be logically attributed to the effect of market manipulations by foreign oil producers.

> There was a gradual increase in relative strength of O.P.E.C. but that increase was not fully evident until 1970 when tightness developed in world oil markets. Choosing their targets carefully, exporting countries selected vulnerable companies (those without ALTERNATIVE SUPPLIES) and improved transfer prices in one area over another. The resulting TEHERAN-TRIPOLI joint agreements of 1971 not only raised the price of oil but also created uncertainty about future prices and signaled a fundamental

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<u>National Science Foundation Report</u>, <u>supra</u> n. 223, at 27.

shift in the bargaining strengths of the two parties.[239]

The public concern and awareness of the market changes and the concomitant domestic fear of extremely high gasoline prices is reflected in these words from Ernest Conine of the Los Angeles Times Editorial Board:

> The bald fact is that no amount of wisdom emanating from next week's economic summit is really going to bring inflation under control as long as the Arab-dominated oil cartel keeps world petroleum prices at their current outrageous levels.[240]

Although some attention must be focused on these artificial causes for the rise of oil prices, primary concentration should be placed on other stable factors which will continue to uphold high prices. These factors include the worldwide energy shortage and related demand for oil and the increasing industrialization of heretofore underdeveloped countries.

Oil is an extremely valuable natural resource. This fact has been repeatedly emphasized by conservation groups who use this high value and the exhaustible nature of oil to bolster arguments in favor of preservation of resources rather than immediate wholesale development. These concerns were expressed at

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239 Ad Hoc Committee on Domestic and International Monetary Effect of Energy and other Natural Resource Pricing, Oil Imports and Energy Security: An Analysis of the Current Situation and Future Prospects (September, 1974), at 4. Hereinafter cited as Oil Imports & Energy Security.

240 L.A. Times, What Can Oil-Consuming Nations do to Pressure Arab Producers.? (September 18, 1974).

a previous hearing in this manner:

> Mayor Dostel approached conservation from another angle. He considered offshore oil and gas deposits as resources to be preserved for future use and posed the rhetorical question:
> 'Shall we continue to deplete this natural, irreplaceable resource because it is expedient or should we preserve it for a time when we or future generations may find it to be of a more critical nature than it is today? . . .' [241]

If the presumption holds that oil values will continue to rise, then the conclusion is apparent that a royalty scheme will realize greater monetary rewards for the federal government over the total time of the lease than a cash bonus system.

(a) What is the Likelihood of Abandonment of Leases and Premature Shut-Downs?

The major problem foreseen for royalty schemes is the possible total abandonment of leases or premature well shut-downs by the oil producers when a downward trend in production revenues develops. The draft E.I.S. states the economic basis for this consequence:

> A royalty bid is calculated so that the firm will retain just enough out of expected production revenues to yield a normal rate of return on production investment. [242]

The National Science Foundation Report discusses this problem as a disadvantage of royalty schemes:

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241 National Ocean Policy Study, supra n. 227, at 36.

242 Draft E.I.S., supra n. 131, at Vol.II p. 415.

Early shut-down hazard economic (social) efficiency requires production to occur until marginal costs equal price. Royalties raise marginal costs above their market level, leading to premature stoppage of oil lifting on a lease. The extent to which this occurs depends upon the actual cost curves and upon tax allowances, subjects which require empirical investigation.[243]

As the E.I.S. points out, however, this problem is probably ephemeral because prudent business practices would dictate the incorporation of this cost into the initial royalty bid. The National Science Foundation Report recommends, "Royalties should decline through time to reduce early shut-down problems."[244]

(b) Will Inefficiency Result from an Inadequate Resource Base?

Another problem raised by critics of royalty schemes is the suspicion that if this bidding makes competition more of a true reality, then independent oil producers might be successful bidders and raise the possibility that, because of their smaller size, they would be unable to meet the financial burden of unexpected emergencies. The E.I.S. frames the problem in this manner:

> The most efficient firm may not get the lease under royalty bidding. Any firm can bid a high royalty. If an irresponsible bidder is awarded the lease there may be significant adverse environmental consequences. In the event of a spill or blowout, the firm may lack the resources necessary to prevent widespread damage. 245

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243 National Science Foundation Report, supra, n. 223, at 35.

244 Id. at 35.

245 Draft E.I.S., supra, n. 131, at Vol.II p. 16.

There are two obvious solutions to the problem. In the case of an emergency, the federal government could intervene and clean up under the regional or national Oil and Hazardous Substances Pollution Contingency Plan. A more thoroughgoing solution would reside in standards established, prior to bidding, for the eligibility of producers based upon a minimum capitalization or other relevant stability criteria.

(c) What are the Administrative Costs?

Will there be a Failure to Develop Lands?

Will there be Suboptimal Extraction?

Will there be Underexploration?

These last four possible problems apply to all leasing schemes, as well as to royalty schemes, because of the necessity for effective agency participation and regulation. As discussed elsewhere, the Department of the Interior should take a much more active role in conducting independent exploration and in regulating the oil producers at all significant stages in oil production. The B.L.M. should be assigned the task of contracting for independent government exploration reports and evaluations, or of negotiating a program of federal exploration and development. The U.S.G.S. should be instructed to thoroughly scrutinize, develop, and review its operating procedures which relate to effective regulation and supervision of the oil producers.

These recommendations for alternate royalty systems will

result in greater administrative costs. Yet such an expenditure will be readily offset by the increased revenue realized by the federal government through more accurate initial evaluations of the true value of leased lands, as well as through more effective regulation of the bases on which royalty payments are made.

2. Although Without Present Statutory Authority, What Are Other Alternative Leasing Schemes?

(a) Rental and Oil Pledge Schemes

Like other schemes, rental and oil pledge schemes serve to transfer risk from the lessee to the government. The crucial questions are whether the schemes share risk as effectively as others and whether they have undesirable side effects.

Rental schemes may not share risks as effectively as royalties. Both avoid large bonus bids. Yet rental schemes may require large payments before firms fully realize potential revenues and/or costs of developing a lease. Royalty schemes, in contrast, require payments only when production commences on a lease and depend upon current market prices. Oil pledge schemes also gear monetary payments to prevailing market prices and seem preferable to rental schemes denominated in money terms.

Some claim that rental or oil pledge schemes avoid the under investment and early shut-down hazards which plague royalty schemes. That claim is incorrect. There may be an early shut-down problem with rentals or pledges, and high marginal costs per unit time (rather than per unit output) may lead to premature

abandonment of leases. Yet there are some real advantages to rental or oil pledge schemes. The schemes are simple to administer. Such information is valuable in deciding whether to meet the next rental installment; there is thus some incentive to rapid exploration. Costs of production may be such that early shut-down is not a substantial problem when compared with a royalty scheme sharing an equivalent amount of risk. Further empirical work is required to decide between royalty and rental schemes, although both schemes may be dominated by profit sharing.

As with royalty bidding, we would suggest caution with respect to rental or oil pledge bidding. If bonus requirements are low, there is the serious hazard of speculative bids leading to underdevelopment of desirable areas. If bonus requirements are high, the scheme will not dominate fixed rental payments, leading to possible distortions in production on adjacent leases.[246]

b. Profit Sharing Schemes

As noted in the E.I.S., the main problem with the profit sharing schemes is that current law apparently does not provide for this method.

> 'The Solicitor's Office of the U.S.D.I. has indicated that a bidding system of this kind is possible under the current law if:
> regulations are changed to define royalties as percentage of something equivalent to net profits; firms bid on the basis of the royalty rate (percentage of net profits) they are willing to pay.[247]

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[246] National Science Foundation Report, supra n. 223, at 43-44.

[247] Draft E.I.S., supra, n. 131, at Vol.II p 417.

Nevertheless, as the National Science Foundation Reports suggests, these schemes have substantial advantages:

> There are some very substantial benefits to profit sharing schemes. They are unequalled as a means of transferring risk to the government for any given level of expected bonus bids. They have no undesirable side effects as long as the stipulated profit base adequately measures true profits. Indeed, one could view a profit sharing plan much as a corporate profits tax but applied to each lease. A desirable feature of corporate profits taxes, as contrasted with excise or other taxes, is their 'neutrality' in affecting the firm's decisions.
>
> The potential disadvantage of a profit sharing plan is that profits may be difficult to measure accurately. How should exploration costs for an entire area be allocated to individual leases? How can overhead costs be allocated? What is a 'fair return' to internally raised capital? These and other questions arise in any situation in which profits must be defined. Providing a strict formula for computing profits has the advantage of minimizing administrative costs and litigation. But strict formulae often fail to capture true profits. Using such formulae may then give misincentives to the firm's decision-making.
>
> Unless care is taken in designing the profit sharing plan, large firms may have an advantage over small firms. This is because losses on a lease are partially reimbursed if they can be used to offset other profitable ventures. A small firm may have no other profitable ventures, implying that they will not receive an offsetting subsidy on their losses. To realize such subsidies under current tax laws, they would be forced to merge with larger firms, thereby reducing competition. Appropriate government policy therefore will be to pay actual compensation if tax offsets are not available. A fully effective scheme would require further research in conjunction with accounting and legal experts.
>
> In sum, the potential economic advantages of profit sharing schemes would seem to warrant a full-scale study of the most efficient ways to implement it. If administrative costs using these ways are still excessive, for the appropriate level of risk sharing, then policymakers should consider some alternative scheme such as

higher royalties or oil pledges with provisions for deducting some portion of exploration and developments costs.[248]

The mathematical theorems and proofs which follow the text of the National Science Foundation report conclude with this summary in favor of profit sharing:

> Discussion: Our proof indicates that profit sharing will generally be a more effective way of sharing risk than are royalties. Profit sharing has two further advantages over royalties:
> 1. Exploration and development expenditures will not be distorted;
> 2. Tracts which would be leased with no profit share will also be leased with any profit share less than one. With royalties, however, the government risks setting a royalty so that bids fall 'below zero', i.e. the tracts are not leased.[249]

The E.I.S. suggests that profit sharing schemes present problems under existing tax laws:

> "The advantages of a net profit sharing system are realized only when:
> 1. 'Net profits' are defined as net income on property after taxes.
> 2. Net profit payments are a share of 'net profits' involving a return on investment in excess of a normal rate of return.
>
> These two conditions are not valid under current tax law. Net profit payments must be calculated prior to tax liability because they are considered as deductions from gross income on property. The second condition above requires a definition of exploration and capital costs distinct from that now used for tax purposes.[250]

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248 National Science Foundation Report, supra n. 223, at 46-47.

249 Id. at 77.

250 Draft E.I.S., supra, n. 131, at Vol.II p 418.

4. Deferred Bonus System

The deferred bonus system, described in the E.I.S., is a variation on the current leasing system. Such a system can potentially alleviate some of the anti-competitive effects of the present system but it also must be carefully examined for other detrimental effects resulting from the present system. The National Science Foundation states:

> Under a deferred bonus system, firms still compete on the basis of bonus payments but with the understanding that the bonus payment will occur over time rather than in one lump sum. For this system to conform to the present law, the bonus payment must be defined as the rental payments during the first five years of the lease. Under this system, the equivalent to current bonus payments would be six times what the firm bids--the bonus payment plus the first five rental payments.
>
> There is really no shifting of the risk in O.C.S. development from the leaseholder to the government under deferred bonuses. Payments to the government are made during the lease's non-productive years and regardless of whether or not production ever takes place.
>
> The advantage of deferred bonuses is that they provide relief to the smaller firm. Such a firm, which might be an efficient and responsible producer, may be at a competitive disadvantage under the current system because of the difficulty it will encounter in trying to assemble the huge sums--from either retained earnings or the money market--now needed to make cash bonus payments during the first year of the lease. The relief is in the form of spreading out the cash flow involved in paying for the right to explore and develop O.C.S. leases. 251

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251 Id. at Vol.II p 418-9.

5. Conclusions

The current leasing process has severe detrimental effects both upon competition and upon the return to the federal government of a fair market value for federal O.C.S. lands. We suggest that another leasing scheme be chosen to mitigate such adverse effects upon the national interest. The additional alternative methods of leasing discussed above, especially the profit-sharing methods, offer strong viable alternative leasing procedures for O.C.S. lands. We suggest that other leasing methods be considered in depth by the B.L.M. before any further effort is made toward granting any O.C.S. lease.

C. Receipt of Fair Market Value

The concern for receiving fair monetary return upon the utilization of national energy resources permeates the entire discussion of O.C.S. development. If the people of the United States are to release these lands for the production of oil, it should be assumed that the national treasury will be as fully recompensed for this use as can be accomplished by reliable economic analysis and adequate regulation.

The U.S.G.S. is the branch of the Department of the Interior granted the authority to regulate oil production. There was a significant economic and scientific study of the operating procedures of this agency done by the Comptroller General of the

United States in February, 1972.[252] The findings of this study, referred to herein as the Comptroller General's Report, will be summarized in this discussion as substantive evidence of the inadequate regulation which has historically characterized U.S.G.S. activity. While many abuses cited in this report have probably been corrected by now, they provide a general perspective on future U.S.G.S. regulations.

The Ad Hoc Committee on the Domestic and International Monetary Effect of Energy and Other Natural Resource Pricing prepared a report for the House of Representatives on December of 1974, titled The Accelerated Development of the O.C.S., Its Problems and Costs. Chapter III of the report directs itself to the problems in management, wherein he states that

> The major conclusion of the paper is that the Department of Interior has been unable to properly manage the current O.C.S. leasing program and will undoubtedly commit even greater disservices to the public interest under the accelerated leasing schedule.

According to the report, the mismanagement results from a variety of factors: an artificial division of function within the agency and a lack of communication between various divisions; understaffing of the agency and consequent reliance on the oil and gas industry for information; serious undervaluation of the worth of a particular tract; inadequate follow-up after a lease sale and an inability to verify industry justifications for shut-

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252 Report to Congress, by the Comptroller General of the United States; More Specific Policies and Procedures Needed for Determining Royalties on Oil from Leased Federal Lands (February 17, 1972).

ting in a producible well. In the words of Congressman Rees:

> The baseline studies and the call for nominations place the responsibility for O.C.S. development into the hands of the oil industry . . . The pre-sale evaluations are often far below what the oil firms are willing to pay . . . And the draft environmental statements are often rush jobs . . . The problems are due to the relationship between the B.L.M. and the U.S.G.S. staff limitations. . . and a general impatience in the Department of Interior.

Thus, the Congressman concludes that there appears to be no evidence that the B.L.M. plans to deviate from its current nominations process.

> Future O.C.S. developments will therefore, guarantee that industry interests receive a greater hearing than the public interest. Nor does it appear, at this point, that the Department of Interior is going to alter the accelerated leasing schedule--in spite of an avalanche of criticism and objections from the coastal states, environmentalists and other interested parties.

Prior to 1961, agency personnel of U.S.G.S. were "operating without a manual containing precise and up-to-date instructions, methods, and procedures."[253] There was no general standard by which such personnel could base their judgments or by which the agency could compare the activities of the personnel throughout the United States.

The Oil and Gas Operations branch of U.S.G.S. issued a manual for personnel in 1961 which consisted "primarily of copies of memorandums--some of which were written as long ago as 1937--on oil and gas activities. Many of these memoranda merely point out how certain cases have been handled and do not provide

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253 *Id*. at 6.

definitive policies for the determination of royalty payments under all situations."[254] The manual had the effect of providing no general standard which would lend uniformity to the decisions made pursuant to its provisions and resulted in reliance upon diverse judgments with no apparent organization of the reasoning which should characterize such decisions.

The lack of reasoned and uniform standards resulted in several crucial disparities in the functioning of the U.S.G.S. in this regulatory context. The inadequacies bore specifically on factors which were necessary to the formation of an accurate evaluation of the value of the oil as it was used by the oil producers in calculating the royalty payments due to the federal government. Initially, no uniform value basis was established for the actual, or market value of the oil by which the federal government could perceive whether or not the oil producers were selling the oil at a reasonable rate.

> . . . In those cases where there is very limited or no competition for oil in a given area or where there are significant differences between the sales prices obtained and those of comparable oil in nearby fields, we believe it essential that Survey Officials consider all pertinent facts and circumstances involved in establishing the sales prices and consider whether the prices are reasonable for use as the basis for computing royalties. [255]

In addition to different values being used as the basis of the sales, there were also significant differences in the

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254 Id. at 6.

255 Id. at 6.

amounts claimed by oil producers for the deduction allowed for transportation costs:

> 'The lack of specific guidelines for considering transportation allowances has resulted in regional officials' considering and evaluating transportation costs on such bases as they deem reasonable. In our opinion, this situation has led to inconsistencies between regions and in some cases within regions, in allowing transportation costs.[256]

A third major disparity arose in the determination of the volume of oil upon which the royalty was paid:

> The lack of specific policies and procedures for use on an agency-wide basis has resulted in numerous inconsistencies in the manner in which regional oil and gas supervisors have carried out their responsibilities for ensuring that royalties were based on (1) values which approximate the fair market value of the oil, (2) deductions for transportation costs which did not exceed actual costs, and (3) total quantities of oil marketed.[257]

As a result of this study, the Department of the Interior directed that the manual be amended and that criteria and standards be developed for the factors enunciated above. Given past history, we suggest that the Interior Department insist that the U.S.G.S. continue to scrutinize and appropriately revise the regulatory procedures applicable to oil production. We also recommend that another agency outside U.S.G.S. conduct periodic evaluations of the effectiveness of U.S.G.S. regulatory practices and procedures.

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256 <u>Id</u>. at 21.

257 <u>Id</u>. at 27.

D. Participation by the Federal Government in Exploration and Development

Past difficulties with the leasing system and its regulatory procedures indicate the necessity of participation by federal government officials in conducting initial explorations and evaluations of O.C.S. lands. Without such an independent governmental decision, the federal agencies are forced to rely upon information from the private oil companies, information which is subject to significant constraints because of the impact of the proprietary privilege problem:

> The history of O.C.S. leasing indicates that the process of selecting the areas to be explored and leased has been left to the discretion of the industry . . . For one thing, we must note in passing that the companies involved have more than a little opportunity to use inside information and contact in getting those areas put up for lease on which they can then bid to best advantage . . . But, even more important, it means that the buyers in a government sale have far more information than the seller, as to the value of the item sold.[258]

Also, coastal planners have little concrete resource information from which to estimate future development pressure. Detailed planning does not normally begin until information about oil and gas resources and anticipated development passes along a slow and reluctant path from industry to the federal government and, thence, in only vague outlines, to the public. Ideally,

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[258] National Ocean Policy Study, supra n. 227, at 39.

however, such information should be obtained even before offshore tracts are leased. This would be possible if the federal government were to conduct its own detailed seismic studies and exploratory drilling.

Some have debated whether the Department of the Interior possesses the authority to conduct independent exploration and evaluation. At previous hearings in Santa Monica, this dialogue took place:

> . . . Deputy Solicitor Lindgren concurred that in his opinion the O.C.S. Lands Act established the policy that exploration and development should be done by the private sector and not by the United States Government itself:
>
> > 'to do our own exploration, to contract for exploratory work to be done for us would require additional authority from Congress" (at 206 Official Transcript)
>
> . . . Mr. Canfield of G.A.O. was not as certain that the O.C.S. Lands Act did not contain the implied authority for the Department of the Interior to explore:
>
> > 'I am not certain I can point to the line saying they don't have it . . . (but) if the Solicitor's Office feels they don't have the authority, the chances are good they won't experience it.' (at 243 Official Transcript) 259

If this delegation of authority issued is resolved affirmatively by the Solicitor General's Office in favor of implied authority to explore, then the Department should consider taking steps to implement this authority. Otherwise, seeking such legislation should be evaluated.

The economic issues discussed above are basically concerned with the optimal preservation of the national interest.

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259 Id. at 39-40.

It is conceded that the private sector will need the incentives provided by the opportunity to profit from exploitation of the O.C.S. leases but this profit margin should be substantially limited by active government participation in as many crucial stages as possible. These lands will reap such large monetary rewards that it is reasonable to assume that both the public and private sectors can experience substantial monetary benefit. Monetary reward, however, must not be the only concern of either private or public bodies. Throughout this analysis, a strong emphasis has been placed upon protection and conservation of environmental interest and upon an orderly and rational development which would spread the benefits and minimize the burdens of O.C.S. development. In recognition of these concerns and the overriding problem of meeting the self-sufficiency goal of Project Independence, this analysis would agree with Deputy Solicitor Lindgren when he said, "While the concerns of and impacts on the people and governments of Southern California re important factors in the decision, in the final analysis, the decision must be made from the perspective and the needs of the nation as a whole." [260]

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260 Id. at 41.

V. PROCEDURES FOR EVALUATION

A. Limitation on Public Participation

1. Short Time Frame for Public Review and Comment

Given the enormous impact of O.C.S. development, we must express our concern over the limited time frame permitted for public review and evaluation of the proposed action. The draft E.I.S., released in October of 1974, is a massive 1300 page document. Upon the release of the E.I.S., the Department of the Interior also announced that public hearings would be held in two or three weeks.

The hearings, however, had been announced before most state and local agencies had even received the draft E.I.S. On behalf of the City of Los Angeles, City Attorney Burt Pines sent a letter to Secretary of the Interior Morton objecting to the lack of time to review the E.I.S. before the hearings. The City was soon notified that the hearings would be postponed for two weeks until early December.

Soon thereafter, the draft E.I.S. was received by local agencies who quickly realized that the magnitude of the program was immense and would have far-reaching consequences that deserved extensive review and examination prior to public hearings. Additionally, in mid-November, 1974, the Federal Energy Agency released the Project Independence Blueprint, an 800-page document which made recommendations to the President for the formulation of a national energy policy.

The time frame in which to evaluate both documents and to solicit scientific expertise was thus totally inadequate. Twenty-five local cities and counties formed a coalition (The Southern California Council of Local Governments) in order to appeal to Secretary Morton for a postponement of the public hearings in order to provide local agencies with adequate time to review the draft E.I.S. and Project Independence Blueprint. Elected officials also expressed their concern, including United States Senators from California and a number of Congressmen. The Department of the Interior, however, evidenced no intention to slow down the decision-making process or to open it up to local input. Ultimately, state and local agencies concluded that, unless an accommodation with the Secretary of the Interior could be reached, the only alternative would be to seek a court order compelling the Department of the Interior to provide the necessary time for a full and adequate public hearing.[261] Just before the suit was to be filed, Secretary Morton met with Los Angeles City Attorney Burt Pines, Senator Tunney and Congressman Bell, and granted a two-month postponement.

2. Hearing Topics Balanced in Favor of O.C.S. Development

In December, local agencies received notifications setting forth the procedures by which the hearings rescheduled for February 6, 7, and 8, would be conducted.[262] The notice contains several procedures which limit public participation

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261 The Administrative Procedure Act, 5 USC Section 553, 554.

262 See General Information Regarding Conduct and Procedures of Hearings Rescheduling of Hearings, United States Department of Interior, Bureau of Land Management, hereinafter referred to as the Memorandum, issued December, 1974.

and inquiry. One of these limitations is the focus at the hearings upon topics which favor O.C.S. development.

The Interior Department, in outlining the scope of the hearings, expressed the hope that six general issues would be fully addressed. Of the six topics that are specified, four will almost certainly result in favorable industry testimony. They are:

a. Domestic and commercial need for the (oil and gas) resource;

b. Industry interest in the proposal;

c. Conflict between user (oil and gas companies) groups;

d. Economic benefits from oil and gas.[263]

Submission of oral testimony and written documents on these issues would over-emphasize the possible economic benefits of offshore drilling, a result contrary to the very purpose of an environmental impact statement. As set forth in N.E.P.A., an environmental impact statement is a detailed discussion of: (a) the environmental impact of the proposed action; (b) any adverse environmental impact of the proposed action; (b) any adverse environmental effects which cannot be avoided should the proposal be implemented; (c) alternatives to the proposed action; (d) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and (e) any irreversible and irretrievable commitment of resources

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263 Id. The other two areas listed in the Memorandum are (E) environmental and conservation, (F) geologic conditions as they affect safety and protection from environmental pollution.

which would be involved in the proposed action should it be implemented.[264]

The purpose of the public hearings is to receive oral and written comments on: (1) the draft E.I.S. and its deficiencies; (2) the potential adverse environmental effects of the proposed agency action; and (3) the possible alternatives to the proposed action. Such a document is meant to assist federal, state and local officials in evaluating the social, economic and environmental costs of federal action. The E.I.S. and the procedures to evaluate it are meant to attain a socio-environmental balance with economic growth.

As stated in Sierra Club v. Froehlke, N.E.P.A. (Section 102(2)(D) 42 USC 4332(2)(E) is an environmental disclosure law which is intended to assure consideration of environmental factors in decisionmaking, even though conflicting with other federal objectives.[265] Striking a socio-environmental balance with economic growth is indeed difficult. Objectivity is essential to ensure that competing interests are meaningfully considered. "Objectivity is required of federal agencies with respect to all environmentally related activities relating to the evaluation of environmental impact, including the selection of consultants, undertaking environmental studies, reliance upon such studies, creation of environmental assessments and coordination with reviewing agencies and preparation

[264] The National Environmental Policy Act of 1969 (hereinafter referred to as N.E.P.A.) Section 102(2)(C), 42 USCA Section 4332(2)(C)(i)-(v).

[265] Sierra Club v. Froehlke, 359 F. Supp. 1289 (1973).

of impact statements."[266]

Unfortunately, the Interior Department seems to have tipped the scales in favor of O.C.S. development in the procedures adopted for the public hearings. Possible alternatives to the proposed action are superficially mentioned. No consideration is given to the irretrievable harm to marine life that would result from offshore drilling, nor are numerous other environmental considerations addressed.

As a result of the questions proposed regarding economic benefits, more deference may be afforded to industry testimony which can address the specific issues outlined by the Interior Department. Participation by private citizens or state and local governments as to those issues is hampered because of the lack of relevant data. Such an overemphasis on economic benefits will have the effect of justifying O.C.S. development without giving full consideration to potential adverse effects.

3. Inability to Ask Questions of Panelists At Hearing

Only panel members, each of whom is from the Department of the Interior, are allowed to ask questions. Participants testifying may not query the panelists. In addition, audience participation is severely limited. If a member of the audience wishes to ask a question, the individual must submit the question in writing to one of the panelists. This procedure does not ensure that the question will be answered.

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[266] *Id.* at 1343.

The Los Angeles City Attorney's Office has inquired of Mr. William Grant, Regional O.C.S. Director, as to why witnesses or members of the audience are not allowed to verbally ask questions. He indicated that B.L.M. and the Department of the Interior considered the hearings to be informational. That response has two relevant implications: (1) the Interior Department views these hearings as a means of gathering information and not as a means of providing information to the public; (2) it removes the Department of the Interior from public accountability.

We disagree with the characterization of public hearings as a one-way informational street. Public hearings should be informative to all participating parties. Inquisitive discussions which yield relevant information should be the premise of rational decisions. By prohibiting witness and audience questions, the Interior Department invalidates the meaning of public hearings.

In addition, the Interior Department also insulates itself from public inquiry, and thereby eliminates any means by which private citizens can meaningfully participate in the decisionmaking process. How can the public be assured that the Interior Department is protecting the national interests? How can the public hold the Interior Department accountable for its actions if there are no mechanisms for inquiry into the decisionmaking process? If inquiry into the decisionmaking process of the Interior Department is prohibited, how

can the public be assured that the department's decision to allow offshore drilling is not an abuse of discretion?

In order to assure impartiality, the public should be informed of the panelists' background and scientific expertise. In addition, because these hearings are for the purpose of evaluating the draft E.I.S., the public should be informed as to whether any of the panelists have personally contributed to, or written parts of, the draft E.I.S.

4. Restrictions on Testimony

A number of restrictions with respect to oral testimony have also been imposed. Speakers, for example, are required to submit advance written requests for speaking time, a procedure which favors organized groups who have time, money and ability to maintain a constant vigilance of proposed agency action. Such procedures may result in excluding private citizens who do not belong to such organizations.

Speaking time for each witness is limited to ten minutes, a restriction which prevents any one speaker from dominating the hearings. An application for time extensions, however, may be submitted to B.L.M. Unfortunately, B.L.M. has failed to establish any criteria for granting or denying such time extension applications. As a result, private citizens may not be able to successfully compete with organized interests for extended speaking time.

Another mechanism which inhibits public participation is the procedure for scheduling speakers. Individuals will not receive notice of the time of the testimony until just prior to the hearings, as a result of which the quality of preparation and actual testimony before the Department of the Interior panelists may be affected. Not knowing the order of testimony until just prior to the hearings also results in a significant obstacle to private citizen participation. Those citizens who wish to testify will be inconvenienced as to approximate time and date of potential appearance. Private citizens who do not submit an advanced written request will be required to hold three days in abeyance until an open time-slot is available. Many private citizens will not be able to participate as a result of time and monetary constraints.

The Department of the Interior states that only one spokesperson shall be allowed to speak on behalf of an organization. If, however, the organization is a "multiple-member" group, an application may be made to the Department to have additional speakers.

The limitation of one spokesperson is an administratively sound restriction in order to free more speaking time for other interested parties. The value of such a restriction, however, may be nullified by allowing additional speakers under a "multiple-member" group classification. The Interior Department does not define a "multiple-member" group. We would like to know the basis on which the Department of

the Interior decides what a "multiple-member" group is. Interest? Size? Potential influence? Diversity? For example, on what basis does the Interior Department determine whether the Friends of the Earth or the American Petroleum Institute are "multiple-member" groups? Thus, without other clarification, the Interior Department internalizes the important decision as to which organizations qualify for additional speaking time, a decision which affects the fairness of treatment for large organized interests as well as private citizen activity.

5. Notice

"Although not bound by the same rules of procedure as courts, administrative agencies are governed by the same basic requirements of fairness and notice, including specificity of notice and opportunity to respond . . .".[267] The Department of the Interior has met these requirements only in form in the procedures set forth in its notice of time, place, and general issues to be discussed.

A basic element of a fair hearing is notification of the substantive issues to be examined. As previously discussed, the purpose of these hearings is to receive oral and written testimony regarding the draft E.I.S. In order to be able to offer these comments, an interested party must have access to the draft E.I.S. As of January 8, 1975, conversations with representatives of the City of San Francisco

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267 Hess and Clark, Division of Rhodia, Inc. v. Food and Drug Administration 495 F. 2d 975 (1974).

indicate that city officials had not yet received notification of the February hearings, nor had they received copies of the draft E.I.S. Attempts to obtain a copy from the Department of the Interior had been unsuccessful. Even if city officials were able to obtain a copy of the draft E.I.S. by January 8, 1975, less than 4 weeks would be left for them to evaluate and prepare any comments they wished to submit.

In addition, we are informed that the Department of the Interior may publish an addendum to the draft E.I.S., but that it would not be available for public scrutiny until just prior to the hearings. Unless additional public hearings are scheduled to allow for evaluation of the additional material, the public participation section of N.E.P.A. will be frustrated. The United States Supreme Court has held that a hearing. . . "must be a hearing in substance and not just in form."[268]

6. Conclusion

We contend that the Interior Department has failed to establish a decisionmaking process which allows full, fair, and equal participation to all interested parties. As Chief Judge Bazelon stated in International Harvester, "The best way for courts to guard against unreasonable or erroneous administrative decisions . . . is to establish a decisionmaking

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[268] Radio Corporation v. F.C.C., 326 U.S. 327 (1945).

process which assures a reasoned decision that can be held up to scrutiny of the scientific community and the public."[269] Such a process must occur prior to any decision to lease in the O.C.S.

[269] International Harvester v. Ruckelshaus, 478 F. 2d 615 (1973) at 652. Cited with approval in Hess and Clark, Division of Rhodia, Inc. v. Food and Drug Administration, 495 F. 2d 975 (1974).

Claims of national security by the Department of Defense have resulted in large areas of potential prime leaseland being excluded from consideration by the Department of the Interior. As a result, other areas, perhaps more environmentally sensitive, may have been designated for potential lease sale. These claims of national security must be carefully reviewed. We turn now to the experience of the Southern California designation process and the role of the Department of Defense.

1. O.C.S. Department of Defense and Southern California

On July 11, 1973, the B.L.M. promulgated a proposed leasing schedule for 17 designated areas, including an identified area off the Southern California coast scheduled for lease sale in May, 1975.[270] On August 30, 1973, the Assistant Secretary of Defense (Installation and Logistics) requested the Department of Navy and the Department of the Air Force to submit comments on the Interior Department's proposed oil and gas lease sale.[271]

The Air Force Department responded with a memorandum dated September 24, 1973 which stated that any Air Force activities affected by the proposed drilling were centered at Vandenberg Air Force Base, California. Apparently, the Air Force and the oil companies had been conducting missile launch operations in concert with drilling activities since 1968. "In practice, a very satisfactory level of cooperation has been established between the Air Force and the companies conducting drilling operations."[272]

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270 38 Federal Register 18473, July 11, 1973, at 1.

271 Memorandum for the Assistant Secretary of Defense(Installation and Logistics). The Dept. of the Navy, Oct. 4, 1973, hereinafter referred to as Navy Memorandum.

272 Memorandum for the Assistant Secretary of Defense (Installation and Logistics) The Dept of the Air Force, Sept.24, 1973, hereinafter referred to as Air Force Memorandum, at 1.

The Air Force concluded that mutual use of the proposed lease land would not hinder its operations or jeopardize the quality of its performance.

In contrast, the Department of the Navy asserted that a large portion of the Southern California coast is necessary for the exclusive use of military operations. In a classified memorandum,[273] the Navy Department stated that the total proposed nominations overlapped the so-called Southern California operating areas where a multiplicity of military operations and functions occur. According to the memorandum,

> It must be divided therefore into: . . . <u>exclusion areas</u> where there is no likelihood of compatible use short of relocation that would be considered either impractical or unreasonable from a national security or cost viewpoint.
>
> <u>Joint Use Areas</u> where both interests can operate side by side provided certain precautions are taken and conditions met, and . . . <u>Free Use Areas</u> where there would be no objection to exploration or exploitation inside the 100 fathom curve.[274]

After the Navy and Air Force memoranda had been received, the Department of Interior evaluated the recommendations along with the proposed lease sites. With respect to the Outer Continental Shelf, the armed forces have no jurisdiction. Jurisdiction is vested in the Department of the Interior under the O.C.S. Lands Act of 1953. On the other hand, the Secretary of Interior

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273 <u>Navy Memorandum</u> at 318. The <u>Memorandum</u> was classified by CNDCOP - 943 and declassified on Oct. 9, 1973 by authority of Capt. G.M. Johnson

274 <u>Id</u>. <u>Navy Memorandum</u> at 318.

has responsibility under the O.C.S. Lands Act to schedule leasing in the best interest of the government Thus, under Department of Defense Directive No. 3100.5, resolution of military and industry differences is made dependent upon negotiation under the supervision of the Interior Department.[275]

On November 26, 1973, B.L.M. designated 7.7 million acres off Southern California for potential lease sale.[276] Apparently, the Interior Department accepted the Navy Department's classifications since the proposed lease land did not contain any of the recommended exclusion areas.[277] In order to accommodate the naval exclusion lands, and to meet the accelerated leasing program of 10,000,000 acres, the Department of Interior expanded the total square mileage of the proposed lease area by expanding the coastal boundaries northerly, southerly and westerly. Amid the proposed O.C.S. lease area, the Department of Interior fashioned borderlines which designated naval exclusion areas.

2. Problems Posed By Exclusion

Under the O.C.S. Lands Act and Department of Defense Directive No. 3100.5, the Interior Department is responsible for scheduling lease sales in the best interest of the government

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275 Id. at 2.

276 Federal Register (November 26, 1973).

277 Navy Memorandum, n. 271, at 2.

and for resolving industry differences through negotiations.[278] These responsibilities of the Department of the Interior mean nonpublic decisions about important matters and the loss of potential O.C.S. development acreage.

First, undefined parameters of authority are granted to the Department of Interior to unilaterally exclude areas along the O.C.S. under the guise of national security, thereby insulating important decisions affecting the environment from public accountability. Such a provision internalizes the mechanisms for resolving a conflict. This aura of secrecy challenges the rationality, the basis, and the validity of the resolution.

We suggest that important questions should have been examined prior to any decision to exclude O.C.S. land by the Interior Department. What inquiries, for example, did Interior Department launch in order to ensure that the Navy Department's contentions were meritorious? What mechanisms can the Interior Department exercise to assure that any possibility for mutual use is considered? Did the Interior Department assume its public responsibility and question the primary motivation of the military and industrial representatives in order to ensure that self-interest was not the controlling factor? The validity of military and industrial requests should at least have been examined. Without mechanisms for public hearings or some form of accountability, resolution of conflicts in matters affecting the public interest lose credibility.

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278 Air Force Memorandum, n. 272, at 1.

A second problem is the exclusion of potential O.C.S. lease areas under the guise of national defense. A study of the Department of the Navy and the Department of the Air Force memoranda serves as a case in point.

The Air Force memorandum is very amenable to mutual use in the proposed area. Under a "hold harmless" agreement, past operations have resulted in a symbiotic relationship, which includes authority to require temporary evacuation of drilling platforms during missile launch periods.[279] In practice, a very satisfactory level of cooperation has been established between the Air Force and the companies conducting drilling operations.

In order to accommodate both increased offshore activity and missile activity, the Air Force recommends that an increased level of control over drilling activities is considered to be prudent because the proposed drilling will take place in areas where programmed impacts of first-stage rocket motors and associated panels will occur. In the past, drilling has been conducted in areas where a vehicle now functioning represented the only potential hazard.[280]

In its judgment, the Air Force finds that mutual use of proposed lease land is feasible and would not hinder its operations or jeopardize "national security".

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279 Id.

280 Navy Memorandum, n. 271, at 2.

On the other hand, the Navy Department did not approve of mutual use for the majority of proposed OCS sites on the grounds that it is not compatible with multiple military operations. (It should be noted that much of the same area is used by both the Air Force and the Navy Department.) In its memorandum, the Navy Department recommends millions of acres to be excluded from any offshore drilling.

The two reasons given for exclusion are "national security" and cost. The Navy Department designated some areas for mutual use (which the Department of Interior recommended for leasing) if oil rigs and other permanent structures were spaced no more than 1 every 10 nautical miles. (This is due to "the extent and nature of military operations . . .")[281] In addition, a few limited areas were classified as free use.

Military operations in excluded areas include principally Project Caesar, the Pacific Missile Range, special use fleet operating areas, a safety area surrounding San Clemente Island, and the submarine transit lanes. According to the memorandum, Project Caesar qualifies for an exclusion classification because there is "no alternate site available. Site location is critical to the security of the United States."[282]

281 Id. at 4.

282 Id.

The Pacific Missile Range (P.M.R.) is situated off the Southern California coast. The P.M.R. through its instrumentation and geographical configuration, provides an area in which fleet and R.D.T.E. programs involving live ordnance and missile firing may be carried out under conditions which allow highly accurate control and data acquisition. There is no area contiguous to the United States, other than P.M.R., in which this range could conceivably be located. Moving the P.M.R. westerly of the San Miguel-San Nicolas access will result in cost and time delay, while data accuracy will deteriorate markedly and operational problems will be compounded.[283] Cost of relocating range capabilities to the outer island is approximately 88.5 million dollars with additional annual costs of 6.7 million dollars. Cost of relocating P.M.R. to stable ocean platforms in lieu of outer island development is 329 million dollars with additional annual costs of 7.3 million dollars. Use of either the outer islands or stable ocean platforms will require the extended area tracking system. Acquisition costs of this system will amount to 57 million dollars. Four to five years will be required to accomplish such moves.[284]

Fleet Operating Areas are located near and around the San Clemente Island which is also part of the exclusion recommendation. These areas are special use areas heavily scheduled for fleet training exercises. This is the only area

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283 Id.

284 Id.

on the west coast utilized for shore bombardment exercises and there are no known alternate sites available. Continued aircraft carrier operations including air to air, air to surface, and surface to air missile and gunnery exercises are conducted in these areas.[285]

In addition, submarine transit lanes are excluded from O.C.S. development. Transit lanes are required for safe undetected submerged transits to and from San Diego. The requirement for undetected submerged transits are vital to the "security of the United States". These lanes are also utilized by surface vessels for safe transit to and from operating areas. It is desirable to maintain at least a 2 mile wide buffer zone clear of underwater obstructions on each side of these transit lanes.

In each military operation the Navy Department asserts that each is vital to "the security of the United States" and thus qualifies the areas for exclusion. We do not take issue with the Navy Department's contention that Project Caesar and the Pacific Missile Range are important military operations. We have no basis for evaluating that claim. The exclusion of millions of acres from potential lease sites under a claim of "national defense" is difficult to understand, however, when the Air Force claims that mutual use is possible.

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285 Id. at 5.

Past experience has indicated that national security has not always been the primary motivation. For instance, the Navy Department could establish some credibility by demonstrating to the Interior Department its need for exclusive use of the suggested areas. The Navy's assertion that its missile areas cannot permit mutual use when the Air Force states that conditional drilling operations are compatible with missile activity.

In addition, designation of fleet operation areas used for training as an excluded area does not seem reasonable. Unless the Navy shows that extensive traffic would preclude any possible or practical conditional drilling, then the Department of Interior should reconsider its present designation and classify such land for mutual use.

Energy independence coupled with prudent and rational use of limited fossil fuels is a primary concern that affects all levels of American society. It, too, can be characterized as a key element of national security. We suggest, then, that a review be made of definitions of national security in order to challenge the Interior Department's unilateral authority to exclude areas without further inquiry into substantive rationale.

The Southern California Council believes that, the public should be allowed to contribute input into the Department of Interior's decision to exclude or propose certain lands for O.C.S. development. Under the present system, the Interior Department sets forth initial calls which delineate possible areas of consideration. Industrial and military interests are allowed to submit their requests. There appears to be no rational reason

for prohibiting public participation. Channels for meaningful cor unications should be established to open up the decision-makil process.

Once the Interior Department has arrived at a decision, its findings should be published in the Federal Register. The Interior Department must indicate, in a detailed statement, the rationale which led to its conclusion.

VI. EVIDENCE THAT THE DETERMINATION HAS BEEN MADE AND PROCEDURES RESULTING IN A PREDISPOSITION TO DRILL

A recent statement by Secretary of the Interior, Rogers C. B. Morton, published in the Los Angeles Times on January 8, 1975, contains these assertions regarding the proposed O.C.S. development:

> Some critics have suggested that new leases should be delayed until coastal states can complete detailed plans for accommodating such onshore developments. I do not believe such delay is necessary or wise . . .
>
> We must move ahead with new offshore exploration as soon as possible -- if only to determine the full extent of these resources. We cannot afford to wait for action by the states, which have only just begun to establish mechanisms for coastal zone planning. And it is not necessary to wait, because no onshore effect will be felt until several years after a lease sale. Moreover, state and local governments can hardly do any detailed planning for onshore impact -- until the exact locations of oil and gas reserves are determined by actual exploratory drilling . . . Let's get on with the job, together. (emphasis added)[286]

The statement above seems to indicate that the Secretary of the Interior has made a definite decision to drill on the O.C.S. Such a predetermination of this essential national decision contravenes the participatory intent of these present hearings.

Monte Canfield, an Energy Specialist with the General Accounting Office who was formerly Deputy Director of the Ford Foundation Energy Policy Project, made the following comments at the hearing:

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286 Rogers Morton; Offshore Oil is the Answer, Los Angeles Times (Jan. 8, 1975).

> The problem is the country is caught in an appetite, a self-fulfilling syndrome we get into. If we tighten belts and conserve energy, we open options up. We may decide in the 80's or sometime to open the Outer Continental Shelf. Perhaps by then, we will have the technology and systems that people will be compatible with. (at 236 of the Official Transcript.)[287]

The Secretary of the Interior apparently has disregarded such cautionary expressions from not only Mr. Canfield but also from economists, scientists, politicians, and public interest groups who oppose precipitous development of the O.C.S. This predetermination to drill is evidenced not only in the Secretary of the Interior's recent statement but also throughout the materials of private and public consulting firms who have furnished information to the Department of the Interior, and it appears to be implicit in the formulation of the draft E.I.S. Such evidence tends to support the notion that the Executive Branch of the federal government has decided to solve the alleged energy crisis and accomplish the goals of Project Independence through the easiest available method - which appears to be accelerated leasing of the O.C.S.

All viable discussion about whether or not O.C.S. development is either efficient or efficacious appears to have ended within the White House and the Department of the Interior. The recent House of Representatives Report concludes that ample reasons exist for continuation of debate and analysis:

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287 <u>National Ocean Policy Study</u>, <u>supra</u> n. 227, at 48.

Research revealed that the leasing of approximately 10 million acres of the O.C.S. was not justified under either a medium development program or an accelerated program. The present level of O.C.S. production could be markedly increased from the exploitation of shut-in wells on existing leases.

The overall conclusion is that given U.S. energy requirements between now and 1985 and the various ways in which these requirements can be met, the accelerated leasing program is unnecessary. (emphasis added)[288]

Yet these reasons do not appear to have had any impact on the predetermination to develop the O.C.S.

Not only does the Department of the Interior appear to be unaffected by such evidence as that contained in the Banking Report, but it also manifests continuing disregard of any dissent through a process of ad hoc decisionmaking based on the predetermination or simply as a matter of routine. There no longer appears to be any agency confusion over whether the O.C.S. development will occur. The relevant agencies consider drilling a *fait accompli*. The following analysis is undertaken to reveal the existence of and reasons for this predetermination and the possible adverse economic and environmental effects which may result from that decision.

We proceed here on the assumption that "orderly development" is preferable to "ad hoc development". Orderly development is particularly difficult in the O.C.S. matter for many reasons,

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288 *Banking and Currency Committee Report*, *supra*, n. 230, at 1.

some of which are articulated in the following statement of Joseph Bodowitz, Executive Director of the California Coastal Zone Conservation Commission:

> . . . the thing that makes planning in regard to the Outer Continental Shelf oil so difficult is it is impossible to understand what the full ramifications are on the basis of anything we have received from the Interior Department . . . it seems to me no one can plan adequately and no one can know what the proper litigation measures are or even if the drilling should take place until you know how, where, when, and what the safety procedures would be and what kind of provisions would be made if there were an oil spill and there is great concern about the recreational and other uses of beaches and perhaps as important as everything, where does the oil go? What are the pipelines? What is the impact on the land? How many refineries and where? . . . It is just the uncertainty that makes this so exceedingly difficult to deal with. [289]

Because information about the proposed development is difficult to organize in an orderly manner does not mean that the federal government should simply abandon the attempt. That difficulty by itself suggests that the federal government should attempt to combine as many of the constituent factors as possible into a rational analysis in order to minimize the difficulty of reaching a decision on whether to drill. Once having arrived at the decision to drill, consideration must then be given to the methods by which the federal government hopes to effectuate the decision. Thus, assuming that the goal of O.C.S. development is perceived as effective implementation of Project Independence Blueprint, the analysis does not leap directly to "How fast can we develop the O.C.S.?" but, rather, to an intermediate step of

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[289] National Ocean Policy Study, supra n. 227 at 42.

"How can we efficiently, equitably, and safely, develop the O.C.S. in an environmentally sound manner?" The latter procedure would be consistent with the statement of the Department of the Interior goals for the draft E.I.S. which are:

> 1. Orderly resource development.
> 2. Protection of the environment.
> 3. Receipt of fair market value.[290]

A. Is the Department of the Interior Reluctant to Await a Comprehensive Federal Energy Policy Statement?

There is general agreement among the political, business, and social communities that the most imperative issue at the moment regarding the national energy crisis is the formulation of an efficient and equitable national federal energy policy. Such a federal policy should, of course, contain both guidelines for future agency actions concerning implementation of the factors which were considered and which form the rational basis for the policy.

Some elements of the business community appear to reveal a strong reluctance to wait for such a federal policy, as in the following statement by the Offshore Oil Drilling Task Force of the Los Angeles area Chamber of Commerce:

> Statement #16: Offshore drilling should not be initiated until there is a national energy policy. Comment: No national energy policy has been conceived within the past fifty years and none is likely, for political reasons, in the next few years when policy decisions must be made to meet future energy requirements. (emphasis added)[291]

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290 Id. at 42.

291 Offshore Oil Drilling Task Force (1974).

The unlikelihood of an articulated national energy policy is based on the assumption that, because no such policy has ever existed, because the problems are so complicated, and because there are many political interests concerned, there never will be such a policy. The danger of such an attitude lies primarily in the results which it is used to justify. Thus, some argue that, because the energy crisis is a present danger and because there is no federal policy nor will there ever be, we must simply steam-roll ahead on a pragmatic basis. Yet we must not focus on the enormity of the domestic energy shortage and on the specter of foreign oil intrigue simply to avoid serious consideration of the difficult issues concerning the total impact of O.C.S. development.

B. Have the Department of the Interior Officials Manifested an Attitude of Predetermination?

It was suggested at the Ocean Policy Study hearings at Santa Monica, California, September 1974, that the public was beginning to doubt the credibility of federal officials in the O.C.S. debate. This attitude was expressed as follows:

> 'Actions subsequent to control of the first blowouts and the on-again/off-again drilling moratorium and the close-following second blowout, further eroded confidence in the Department of the Interior to the point that some even accused the government officials of bad faith, malfeasance, and benign neglect.' (emphasis added)[292]

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292 Water and Energy Committee Report, Los Angeles area Chamber of Commerce.

There has also developed a growing awareness that federal officials are proceeding in total disregard of the facts involving prior oil blowouts and assuming the inevitability of the intent to lease on the O.C.S. The possibility of a predetermined decision by the Department of the Interior was expressed as follows:

> (the) announcement of the call for tract nominations on 1.6 million acres of O.C.S. offshore of Southern California, by the Bureau of Land Management (BLM) of January 2, 1974, came within five years after the Santa Barbara Blowout. According to many public witnesses and local officials who testified at the Ocean Policy Study hearings at Santa Monica, California, September 27 and 28, 1974, the most recent Interior Department announcement came without forewarning. However, there is evidence that a tentative outer continental shelf leasing schedule existed as an internal document within BLM in July, 1973. (See Exhibit B, complaint filed in U.S. District Court, Central District of California, August 5, 1974, <u>California</u> v <u>Morton</u>, CIV 74-2374-AAH)[293]

C. Has the Oil Industry Exercised Undue Influence on the Department of the Interior?

Substantial evidence suggests that the business community has exercised a persuasive influence on decisions made by federal government officials about O.C.S. To avoid any "anti-business" responses to our claim of undue influence, we intend to provide specific instances of such influence.

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[293] <u>National Ocean Policy Study</u>, <u>supra</u> n. 227, at 14-15.

Our specific concerns regarding the oil companies include: (1) the failure to report to relevant federal officials the possible lack of industrial personnel and materials to appropriately develop the O.C.S. at the present time; (2) oil industry generation and control of the data upon which federal officials base their decisions; and (3) the impression that the oil industry may exercise undue influence over its regulatory agency.

1. Is there Evidence that the Oil Industry has Inadequate Personnel and Materials?

A recent comprehensive report on the accelerated development of the O.C.S.,[294] prepared by the House Banking and Currency Committee, explores the possible lack of oil industry capability to effectively and efficiently develop the O.C.S. at the present time. Chapter 2, entitled "Materials and Equipment Under an Accelerated Outer Continental Shelf Leasing Program", specifically focuses on present problems with industry technology and sources of supply. The serious concern of these researchers is expressed as follows:

> "A central question concerning the wisdom of accelerated development is whether the oil industry has the ability to keep production abreast with the anticipated increased domestic supply of crude oil. An essential component of this production capability is

[294] Id. at 14.

the supply of equipment and materials needed to mine off-shore oil. The study finds that there are projected shortages in steel and steel products, rotary drilling rigs, mobile drilling platforms, and fixed drilling platforms. *

We must emphasize that this comprehensive and authoritative report exists and is available for consideration by the Department of the Interior. Our analysis here will highlight the most important factors set forth in that report that suggest insufficient industry capability to develop the O.C.S.

There is a shortage of available steel. There is a shortage of skilled labor to operate the drilling platforms.[295] Many oil refineries are not able to operate at total productive capacity because there is no uniform construction program for oil refineries.[296] Current refinery expansion, and construction of new refinery capacity, are not progressing fast enough to keep pace with the growth in demand for oil products.[297] There continue to be substantial problems surrounding the construction of pipelines and the development of deepwater port facilities.[298]

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* <u>Banking and Currency Committee Report</u>, <u>supra</u>, n. 230 at 2.

295 <u>Id</u>. at 1, 2.

296 <u>Id</u>. at 11.

297 <u>Id</u>. at 14.

298 <u>Id</u>. at 17.

The factors above are but a few of those which in a cumulative grouping led the researchers in the staff of the Banking and Currency Committee to conclude that:

> In light of this situation, the Interior Department's proposed acceleration of the Outer Continental Shelf Leasing schedule, which calls for the lease sale of 10 million acres in 1975, must be criticized. While the intention of this policy to use the crude oil produced from the OCS as a supply base for domestic refineries, and thus reduce the amount of crude oil imported from foreign sources, is basically sound, potential problems may arise, such as what happens if the oil discovered on the OCS is of a quality and grade that cannot be processed at domestic refineries without substantial adjustments being made to distillations units. <u>It is our opinion that further consideration and examination of this proposed policy of accelerated OCS leasing is warranted</u>. (emphasis added)[299]

We have set forth in a general way the factors which suggest a lack of industry capability to develop the O.C.S. in order to focus sharply upon the fact that the oil industry has not manifested a good faith attempt to fully inform the Department of the Interior of these technological inadequacies or the Department of the Interior, if such information was available, has not manifested a serious consideration of these matters in the E.I.S..

2. What is the Effect of Department of the Interior Reliance Upon Industry Accumulated Data? What is the Effect of the Proprietary Privilege Attached to some of these Findings?

Concern has often been expressed over whether the oil

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299 *Id.* at 20.

industries were in a superior bargaining position because of their generation and control over dissemination of oil development data. California State Controller Kenneth Cory expressed his concern as follows:

> The history of Outer Continental Shelf leasing indicates that the process of selecting the areas to be explored and leased has been left to the discretion of the industry . . . For one thing, we must note in passing that the companies involved have more than a little opportunity to use inside information and contact in getting those areas put up for lease on which they can then bid to best advantage . . . But, even more important, it means that the buyers in a government sale have far more information than the seller, as to the value of the item sold. (emphasis added) (Official Transcript at 68)[300]

The oil industry's control over the data used for the Department of Interior decisions is secured by their claim of proprietary information which avoids its public disclosure. The Freedom of Information Act, 5 U.S.C. 552, exempts trade secrets and geological and geophysical information and data. Accordingly, in terms of pre-site data, the government receives only what the industry desires to give it and even this "will remain confidential on request". (39 Fed. Reg. 6541.) The fact that the Department of Interior is contracting to spend 6 million dollars of public money for geologic seismic data does not detract from its proprietary nature. (See Fed. Reg. for Jan. 31, 1974.)

The Department of the Interior, realizing the problems that arise from non-disclosure of many material facts, proposed rule changes concerning submission and disclosure of O.C.S. geological and geophysical data in the Federal

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300 National Ocean Study Policy, supra n. 227, at 14-15.

Register on May 16, 1974. (39 Fed. Reg. 17446) The Department of the Interior states:

> . . . that the submission of such data to the Geological Survey and the disclosure of such information to the public will serve the public interest, conserve natural resources, encourage competitive bidding, and assure the receipt of a fair market value for federal resources. (39 Fed. Reg. 17446) (emphasis added)

As might be expected, these changes were met with massive resistance from industry at a public hearing conducted on July 15, 1974. The oil industry claimed that such disclosure would be (1) a confiscation of proprietary rights, (2) exceed the limits of O.C.S.L.A., (3) simply add one more confused estimate, and (4) choke off technological innovation and competition. The Western Oil and Gas Association supported these self-protective arguments with the assertion that full disclosure would, in fact, be "unAmerican" because "if available to all, there would be no incentive to pay for doing the work in the first place."

From a rational standpoint, it should be apparent that the primary question is not whether research companies will be paid but rather what methods insure the fullest use of material information gathered by such companies. Of course, someone will have to pay for data gathering. It may be private industry or it may be the government who pays. Once paid, however, the company should have no further interest in the dissemination of this information so long as there is no abridgment of any relevant copyright problems.

W.O.G.A.'s position leads to the conclusion that private

companies which gather such data want payments from anyone who uses the information. Yet to accept that argument is to assume that undue enrichment to these companies would result. These companies, however, presumably calculate the fair cost of information gathering at the time they enter into the contract with the original purchaser. In terms of equity, once there has been fair payment, then these companies should have no right to continuing secrecy unless there is a specific legally-recognized infringement such as a trade secret.

The information that we are concerned about should not be secret, for it describes a national resource. As general information regarding geological and geophysical data, it is not a carefully-guarded formula. The Council on Environmental Quality Report discusses proprietary data as follows:

> . . . it is not clear that the release of processed seismic reflection data would substantially jeopardize the competitive positions of the oil companies in relation to the government or to each other, because they recitatively share group-shoot data with the government and among themselves. Moreover, because competition dissipates after a lease sale, the justification for continuing to withhold exploratory data after lease awards is unclear. (at 9-16)

What, then, is the effect that such private industry attitudes about proprietary data have upon the decisionmaking function of federal officials. Officials of the Department of the Interior have a very difficult task to remain totally immune and neutral to industry claims for nondisclosure. Yet a neutral attitude is precisely what the public expects from governmental officials. The public suffers from lack of information and lack of industry participation. The Council on Environmental Quality

report summarizes these latter inequities as follows:

> The fact that the Interior Department treats industry data as proprietary 'severely restricts the effectiveness of the public review process,' particularly in commenting on environmental impact statements. Although there may well be sound reasons for withholding some data in some circumstances, the competitive justification for a blanket prohibition of public disclosure is not clear. (at 9-16)

3. Do the Oil Companies Exercise Undue Influence on the Department of the Interior's Decisionmaking Process in Regard to O.C.S. Development?

Concern has often been expressed about the problems inherent in the creation of a regulatory governmental agency whose purpose was to effectively regulate strong power blocs such as the oil industry. That concern is heightened by growing public suspicion that many regulatory agencies appear to be unduly influenced by those they seek to regulate either by direct or indirect methods. Such awareness is typified by one political theorist as follows:

> . . . criticism voiced by Theodore Lowi that the very vagueness of post-1937 Congressional allegations of power was producing 'bargaining on the rule: between regulatory agencies and the supposed object of their regulation, resulting in a governmental inability to achieve a "rule of law" grounded in clear decisions about values.' 301

On October 13, 1974, the Los Angeles Times published an article by Irving Bengelsdorf, Director of Science and Technology

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301 Oil Pollution and the Public Interest, A study of the Santa Barbara Oil Spill, at 100. Hereinafter cited as Oil Pollution and the Public Interest.

at California Institute of Technology. Bengelsdorf said that the Secretary of the Interior, Rogers C. B. Morton, appeared at a White House briefing of leaders of the oil industry on August 16, 1973. Morton told these representatives of the oil industry:

> I would just like to say . . . that the office of oil and gas is an institution which is designed to be your institution, and to help you in any way it can . . . our mission is to serve you, not to regulate you. We try to avoid it . . . I pledge to you that the department is at your service. [302] (Emphasis added)

We do not intend here to evaluate whether the oil industry exercises undue influence over the Department of the Interior, or its regulatory branch, the U.S.G.S. We raise the issue only as another factor which suggests that O.C.S. development has not been adequately scrutinized and investigated by the appropriate federal officials.

D. Was an Assumption of Predetermination Manifested Throughout Earlier Stages of the Leasing Procedures?

There was a substantial assertion made at least as early as the Santa Monica hearings in September, 1974 that the Department of the Interior was proceeding upon an assumption that drilling will take place. As memorialized in an affidavit from a member of the Attorney General of California's Task Force in these matters:

> . . . 4. At the meeting July 11, 1974, [California Resources Agency Conference Room, located at 1416 Ninth Street, Sacramento, California] representatives of various agencies of the State of California

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302 CIV 74-2374-AAH.

and the U.S. Department of Interior to discuss potential Outer Continental Shelf (OCS) development off the Southern California Coast], Jared Carter, Deputy Undersecretary of the Department of Interior, made several statements concerning the proposal of the U.S. Department of Interior to engage in the development of oil and gas resources on the Outer Continental Shelf (OCS) off the Southern California coastal area. He stated in substance: (a) that he was sent to California to do a selling job with the citizens of California, convincing them of the feasibility and merits of OCS development, . . . (b) that every conscientious decisionmaker is convinced Outer Continental Shelf Oil and gas development is the way to go. (Emphasis added.) 303

State Assemblyman Alan Sieroty voiced a concern in the California hearings about whether the decision to open the O.C.S. has already been made when he stated:

> . . . I think a lot of people are suspicious about government generally these days, and wonder whether the fact that the President of the United States made a statement some time ago about opening up this area for oil drilling means that it's an accomplished fact: that no matter what environmentalists think, no matter what economic, social and other considerations may bring to light that it has already been decided to go ahead. . . 304 (emphasis added)

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303 Exhibit X. Attorney General's Material. Affidavit of Robert H. O'Brien at 1.

304 Exhibit J. Attorney General's Material. Assembly Select Committee on Coastal Zone Resources. Apr. 9, 1974, Santa Monica, California Hearing: Offshore Oil Drill at 21. Hereinafter cited as Exhibit J Attorney General's Material.

As well as substantially influencing later actions by federal officials who act as though the issue has already been resolved, the implicit assumption that drilling will take place nullifies the overriding principle of N.E.P.A. that there must be effective public participation in the decisionmaking process. That this principle is firmly imbedded in N.E.P.A. determinations and that federal officials do, at least, recognize it verbally, is evident from the following statement in the National Ocean Policy Study:

> . . . Duke Ligon, of FEA, referring to the NEPA process stated: ' . . . (This) procedure is designed to assure the opportunity for all responsible public and private points of view to be expressed. Interested parties are encouraged to involve themselves at appropriate stages in the development of the environmental impact statement'.[305] (Official Transcript at 49.)

Ligon stated further that "a <u>Secretarial decision to lease OCS lands assumes that national, state, and local governments have been involved in the process from the beginning to end</u>." (Official Transcript at 49.) (Emphasis added)

A contradiction exists between what federal officials mistakenly believe to be the case -- that there has been effective public participation and dialogue -- and what is, in fact, the case - that the public is listened to only in a <u>pro forma</u> manner after the decision has already been made.

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305 <u>National Ocean Policy Study</u>, <u>supra</u> n. 227, at 41.

E. What is the Adverse Effect of an Ad Hoc Decision-making Process?

Is Orderly Planning More Desirable than Expedient Measures which do not Consider Detrimental Consequences?

The assumption that drilling will take place has also led to the possibly disastrous consequence of providing a basis for a series of ad hoc secondary decisions throughout the appropriate agencies. The theoretical objection to this type of disconnected decisionmaking is that it leads to undue uncertainty and confusion. Theodore J. Lowi, a prominent political scientist, discusses this problem in his book THE END OF LIBERALISM (New York, Norton, 1969) where this analysis is found:

> . . . Lowi's emphasis is on partial decisions in the sense of incomplete decisions-on the 'non-cumulativeness' of governing experience when there is bargaining about each decision without a guiding set of rules and cumulative, coherent precedents. [306]

Daniel Moynihan also expressed a concern with this issue in his article,"Policy vs. Program in the '70's", in the PUBLIC INTEREST, No. 20: 90-100 (Summer 1970) where he argues for the substitution of coherent planning instead of ad hoc "program-making".

One method of such ad hoc decisionmaking is to simply avoid the problem by recategorizing some debatable issue. This was seemingly evidenced in the Department of the Interior's attitude to public criticism of the facts surrounding the "call for nominations".

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306 Oil Pollution and the Public Interest, supra n. 301, at 152.

'. . . the Department of the Interior uses a highly technical approach to interpret and administer the regulations promulgated under the Outer Continental Shelf Lands Act. One example is the determination that the 'call for nominations is not a decision', that a 'decision' is not made until it is decided which tracts are to be sold. While perhaps technically defensible, the non-federal witnesses did not consider the distinction as a reason not to freely consult state and local representatives prior to the call for nominations. 307

Some physical proof of ad hoc decisionmaking at higher executive levels may be inferred from the fact that after President Nixon announced a plan for expanding O.C.S. development, the personnel in the B.L.M. in Los Angeles subsequently increased. This fact was discussed as follows at Santa Monica:

Mr. Douglas: When your staffing was increased, was that before or after President Nixon's announced plan for expanding these OCS activities.
Mr. Grant: The office wasn't opened until after that announcement. It was opened in September . . . 308

The office was clearly opened to administer a program of regional O.C.S. leasing.

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307 National Ocean Policy Study, supra n. 227, at 3-4

308 Exhibit J. Attorney General's Material, supra n. 304, at 28.

F. What Other Considerations Create Inferences That a Predetermination Has Been Made?

Have there been Previous Appropriations Without an E.I.S.?

Is There a Financial Advantage to the Department of the Interior in Maintaining the Status Quo?

Has there been Consideration of the Irreversibility of Oil Development?

The California Attorney General, in the case of California v. Morton, argued that N.E.P.A. had been violated by the Department of Interior's actions which were taken without an E.I.S. We agree. Specifically, the 1973 five-year leasing program, and the initiation of Lease Sale No. 35 off the Southern California coast, do not meet the requirements of N.E.P.A. The Department of the Interior contends that the decisions inherent in these previous actions were not decisions for the purposes of N.E.P.A. Yet, the language of N.E.P.A. itself provides the surest measure of Congressional intent. While there is no direct mention of impact statements or regulations, long-range plans, or policy statements, Section 102(c) statements are required for "every recommendation or report on proposals for legislation." The words "other major federal actions" should be read to include a program with the breadth and potential impact of O.C.S. leasing.

Numerous federal courts have found it necessary for federal agencies to provide environmental impact statements in situations where the relevant federal agencies felt that such a

statement was not necessary. The case <u>Scientists' Inst. for Public Info., Inc.</u> v <u>Atomic Energy Commission</u> (AEC), 481 F. 2d 1079 (D.C. Cir. 1973) includes a statement of the court to the effect that whenever there exists a federal agency program of some magnitude and that program falls within the confines of N.E.P.A., the federal agency sponsoring that program must prepare a detailed statement thereon. This "program" statement should not be concerned with the specific environmental issues of a particular facility or a particular tract or a particular phase of the program, but must be concerned with "the broader considerations necessarily involved in an impact statement on the overall program." (<u>Scientists Inst.</u> v <u>AEC</u> at 1093.) The same principle applies to the situation before us.

When it appears that the Department of Interior has made an accurate interpretation as to the policies of N.E.P.A., courts will compel the relevant agency to meet the requirements of N.E.P.A. if the court finds that those requirements have been violated. We suggest that the Department of the Interior should be encouraged to consider more fully the implications of the proposed O.C.S. development.

Finally, we wish to briefly focus upon the fact that oil development involves the exploitation of a finite natural resource which may soon be exhausted. This fact means that such development will be irreversible. The Department of the Interior, in manifesting an attitude that suggests that the decision to develop such land has already been made and that there will be no viable discussion about the proposed action, leads to the conclusion that

the Department of the Interior is either unaware of the irreversibility of its decision or disregards the importance of the exhaustible characteristic of the national oil resources.

CONCLUSION

We believe that a predetermination of these issues has been made and has resulted in a predisposition to drill. Public participation in the decisionmaking process concerning the utilization of valuable national resources has therefore been rendered ineffectual. We believe that effective policy-making by the Department of the Interior requires the substitution of a rational process instead of ad hoc decisionmaking, particularly in view of the fact that O.C.S. leasing is an integral part of the implementation of a national energy policy. The Department of the Interior should proceed to accumulate the necessary scientific and technical data to formulate knowledgeable answers for questions involving the implementation of O.C.S. development as well as the larger social concerns about protection from adverse effects on our social, economic and environmental welfare. Because such data does not appear to have been assembled or seriously sought out by the Department of the Interior, the B.L.M. has not had the opportunity to work from a sufficient scientific data base. There is now available sufficient scientific, political, economical, sociological and environmental information. The Department of the Interior officials must compile such material and reconsider its commitment to O.C.S. leasing.

We believe that for the Department of the Interior to proceed with O.C.S. leasing in the manner and within the time limits that are now proposed would result in circumventing the purposes of the 1972 Coastal Zone Management Act. We strongly urge that leasing of coastal waters be postponed until the affected states have a reasonable opportunity to adopt coastal management plans. (We note in this regard that the efforts of the states to develop management plans have been hampered by a lack of funds. Although Congress directed that grants should be made to states for preparation of plans, a substantial portion of those funds which were to be allotted were impounded by former President Nixon.)

In passing the Coastal Zone Management Act, Congress found that:

> The increasing and competing demands upon the lands and waters of our coastal zone occasioned by population growth and economic development, including . . . . extraction of mineral resources and fossil fuels. . . have resulted in the loss of living marine resources, wildlife, nutrient rich areas, permanent and adverse changes to ecological systems, decreasing open space for public use, and shoreline erosion. . . . (1451 subsection c.)

Congress also found that "important ecological, cultural, historic and aesthetic values in the coastal zone which are essential to the well-being of all citizens are being irretrievably damaged or lost . . . . (Section 1451 (e)), (emphasis added), and that:

> Special natural and scenic characteristics are being damaged by ill-planned development that threaten these values. (Section 1451 (f))
> The key to more effective protection and use of land and water resources of the coastal zone is to encourage the states to exercise their full authority over the lands and waters in the coastal zone by assisting the states, in cooperation with federal and local government and other vitally affected interests, in developing land and water use programs for the coastal zone, including unified policy, criteria, standards, methods, and processes for dealing with land and water use decisions of more than local significance. (Section 1451 h.)

Moreover, Congress has declared that it is the national policy "for all federal agencies engaged in programs affecting the coastal zone to cooperate and participate with state and local government and regional agencies in effectuating the purposes of this title" (Coastal Zone and Management Act , Section 1452 sub. c.)

Pursuant to the California Coastal Zone Conservation Act of 1972 (California Public Resources Code Section 27000 etc.), the California Coastal Commission is in the process of adopting a coastal zone management plan. In terms of the potential impact of O.C.S. development, the most important portion of that plan is the energy element. Action was taken on January 26 to approve the proposed energy element.

In order to meet the reouirements of the Coastal Zone Management Act, this plan must include:

> A definition of what shall constitute permissible land and water uses within the coastal zone which will have a direct and significant impact on the coastal waters. . . . (Section 1454 sub. b. sub. 2.)

The plan adopted by the State Commission will be submitted to the State Legislature and then, if approved by the State Legislature, submitted to the Secretary of Commerce for his approval. After the Secretary of Commerce approves a state plan, the Coastal Zone Management Act provides that:

> Each federal agency conducting or supporting activities directly affecting the coastal zone shall conduct or support those activities in a manner which is, to the maximum extent practicable, consistant with approved state management programs. (Section 1456 (c) (1)) Any federal agency which shall undertake any development projects in the coastal zone of the state shall insure that the project is, to the maximum extent practicable, consistent with approved state management programs. (Section 1456 (c) (2))

In view of the fact that California's energy element of the coastal plan is pending, and since California has made every effort to provide for prompt adoption of the coastal plan, it would seem unreasonable and unfair for the Department of the Interior to proceed with the proposal in a precipitous manner which may endanger the implementation of a state's carefully drafted plan.

The need for coordination is made apparent by several conflicts which exist between the proposed O.C.S. development and the policies regarding petroleum exploration and production adopted by the Coastal Commission on January 26. The overriding policy adopted by the Commission was that the need for offshore oil development should first be clearly determined:

Because of the risk of oil spills, the adverse visual impact of oil platforms, and the need for related onshore facilities that would necessarily accompany development of the Outer Continental Shelf (O.C.S.), new offshore oil and gas development of state or federal lands, shall be permitted only after:

a. A comprehensive analysis has determined the need for California offshore production in light of the anticipated inflow to California . . . of oil and other forms of energy from all other sources, including onshore oil production, Alaskan North Slope oil and gas production, production in other regions of Alaska, foreign oil in gas imports, and in view of California's projected capacities to refine and store the anticipated inflow of oil from sources other than new offshore production; or

b. Development of the O.C.S. off California has been clearly identified as an integral and priority part of a comprehensive, balanced national energy conservation and development program (Policy 16).

As noted elsewhere, the proposed O.C.S. development is not a part of a comprehensive national energy conservation and development program. Until such time as a comprehensive plan is developed and the role of O.C.S. development in that plan is determined, no major offshore oil production activity should occur.

Another petroleum policy adopted by the Coastal Commission is to allow offshore drilling only where safe (Policy 18):

To minimize the risk of adverse environmental effects resulting from oil discharges, offshore drilling and production shall be permitted only where it can be demonstrated that:

a. The most advanced state of-the-art drilling and production technology is utilized.

b. The geologic characteristics of the area have been adequately investigated and are consistent with safe drilling and production.

c. The proposed well sites are the least environmentally hazardous and disruptive sites feasible.

No similar policy safeguards guide the proposed O.C.S. development.

Another policy adopted by the Coastal Commission encourages consolidation of drilling, production and processing sites (Policy 19):

> To minimize construction in offshore areas and development of related onshore facilities, all petroleum-related development and operations shall be unitized or consolidated . . . to the maximum extent feasible, unless it can be shown that unitization or consolidation will not reduce the number of facilities, or significantly reduce the number of producing wells or support facilities required to produce the reservoir economically and with minimal environmental impacts.

No similar policy exists in the proposed O.C.S. development.

The Coastal Commission also requires the use of submerged completion and production systems where feasible and environmentally safe (Policy 20):

> To reduce the visual impacts of offshore operations, subsea completion of wells and submerged production systems shall be used where environmentally safe, as demonstrated through adequate testing of equipment, and where technically and economically feasible. In those areas where all platforms or islands would have a substantial adverse environmental effect, including degradation of aesthetic values, no offshore drilling should be permitted unless and until subsea completions or submerged production systems are demonstrated to be environmentally safe.

No similar policy safeguards control the proposed O.C.S. development.

Another policy of the Coastal Commission is to minimize the impact of onshore facilities (Policy 22):

> All onshore drilling, production and onshore support facilities for offshore operations, including separation plants, pipelines, terminals and storage facilities, shall be designed and located to minimize their environmental impacts consistent with recovery of the resource. . . Where such development would necessarily result in substantial adverse impacts to the resources of the coastal zone, it shall be permitted only upon a demonstration that there is a need for the project. . ., that alternatives would have a greater adverse environmental impact, and that there is little likelihood of improvement in technology that would substantially reduce such impacts in the immediate future. . . .

No similar policy safeguards guide the proposed O.C.S. development.

The California Coastal Commission also advocates the establishment of an oil spill liability fund (Policy 26):

> To encourage the use of the highest state-of-the-art technology in offshore petroleum operations, ensure the effectiveness of oil spill contingency plans, guarantee prompt compensation of damages resulting from oil spills, and in the absence of existing federal legislation adequate to fully achieve those ends, the California Legislature should enact legislation requiring that:
>
> a. Each approved applicant shall be required to show evidence of secured financial responsibility to the State Lands Commission in the amount of $10 million for each individual lease prior to the initiation of any offshore drilling.
>
> b. Each approved applicant shall be required to pay a two cent fee on each

barrel of petroleum produced from a well on State lands, which shall go toward creation and maintenance of an Oil Spill Liability Fund.

The Coastal Commission strongly recommends federal legislation to create a single national oil spill liability fund in order to compensate damages caused by spills from tanker operations and offshore oil exploration and development. The proposed O.C.S. development fails to provide for such a fund.

The Coastal Commission has also adopted a policy providing for protection against any adverse impact of O.C.S. development (Policy 27):

> To ensure that production of petroleum from federal areas more than three miles off the California coast has no substantial adverse impact on the California coastal zone, and that federal O.C.S. development and related activities are compatible with goals set forth in this and other elements of the Coastal Plan, the Coastal Commission or the agency designated to carry out the Coastal Plan, the California Legislature, the California congressional delegation, the State Lands Commission, the Division of Oil and Gas, and all other concerned agencies should seek agreement from the Department of the Interior and other federal authorities that <u>no federal O.C.S. leases will be approved by the Department of the Interior unless:</u>
>
> a. Need for federal O.C.S. development off California has been clearly determined. . .;
>
> b. Opportunities for effective review of proposed O.C.S. development plans are provided for the general public, interested units of state, regional, and local government, and other segments of the communities most immediately affected by O.C.S. development activities;
>
> c. One, five, and ten-year plans for petroleum production and all related

development. . . and their impacts on the California Coast, are fully developed and disclosed;

d. The leases in question are clearly separated from State petroleum sanctuaries to prevent drainage of oil and gas reservoirs that may lie partially on State submerged lands;

e. Petroleum production under federal jurisdiction off the California Coast is made subject to safety standards at least as stringent as those for production on State-regulated offshore areas. . .;

f. The possibility of unitization or consolidation of all operations and facilities has been fully evaluated. . .;

g. The possibility of use of submerged drilling, completion, and production systems that have been adequately tested to meet rigid environmental safety standards has been fully evaluated as a partial alternative to platforms;

h. The federal government has agreed to provide monies to California (and to other coastal states) either through a fee related to production volumes, or by making available a portion of its revenues from O.C.S. lease sales or production royalties, or by granting funds from some or other source, to assist the state and local governments in planning for and overcoming or mitigating any adverse impact of this production. . . and to assist the state and local governments to purchase land for recreation or provide other amenities along the coast to help offset the impact of O.C.S. development;

i. Sites and tracts should be designated as sanctuaries if they are unusually

> subject to the risk of oil spills due to geological seismic disturbance or if they offer unusual coastal aesthetic assets or if the local economy is particularly dependent upon the production of coastal aesthetic assets. Portions of the Santa Barbara Channel and Santa Monica Bay would appear to be candidates for sanctuary status.

The draft E.I.S. for the proposed O.C.S. development fails to provide for the protections called for by the Coastal Commission. Indeed, unless and until these concerns of the Coastal Commission are addressed by the Department of the Interior, there exists a substantial risk that effective implementation of the Coastal Zone Management Plan for California and for other coastal states will be rendered impossible. The sharp conflict in the governing policies for O.C.S. development and for coastal zone management indicate the need for a delay in the proposed development in order to ensure the resolution of those conflicts in a manner that protects the California coastline.

Many sources have accused California and other coastal states of being parochial about their concern for protecting their coastal resources. We wish to emphasize that at this point we have not taken a position of unalterable opposition to O.C.S. development. We are now only concerned that too many questions have been left unanswered. It is our strong belief, as is declared in the California Coastal Zone Conservation Act, that the coastal resources belong to all of the people. As Congress stated in the Coastal Zone Management Act,

"There is a national interest in the effective management, beneficial use, protection, and development of the coastal zone. . ." (Section 1451 a.) Our interest in sound management of this precious natural resource pertains equally to the sound management of our national petroleum resources. The question at this point, rather than whether our petroleum resources should be developed, is how, where, when? We raise our opposition to the Department of the Interior's current plans for O.C.S. development acting as protector of natural resources on behalf of all of the country. That this is a national resource is eloquently stated in the Coastal Zone Management Act.

A delay in O.C.S. leasing, which would allow California and other coastal states to complete their management plans, would have the secondary benefit of allowing each town to answer the important questions that we have raised in this testimony. It would also provide opportunity for completion of many of the base line studies which are now being prepared. When those studies are completed, we hope the country will have the necessary data to do an insightful analysis of the real environmental, economic and social impact of O.C.S. development.

We, therefore, recommend postponement of O.C.S. development until coastal states have had time to complete their management plans.

VIII CONCLUSION

This Analysis does not presume to be a comprehensive review of all the problems associated with O.C.S. development. Nor does it pretend to have answers to the many difficult questions raised.

The purpose of the Analysis is primarily to raise questions not addressed, or inadequately treated, by the E.I.S. Based on our Analysis, however, we have arrived at the following conclusions:

1. Any decision in regard to expanded O.C.S. development must be made as an integral part of establishment of a national energy program.
2. Adequate demand projections have not been provided on which to base a decision in regard to expanded O.C.S. development.
3. The need for a comprehensive energy conservation program has been demonstrated, and we must explore reduction of demand as an alternative to expanded O.C.S. development.
4. There are many energy sources which may be economically and environmentally preferable alternatives to O.C.S. development which must be explored.
5. We must explore whether producible wells are shut-in in the Gulf of Mexico which could be produced as an alternative to expanded O.C.S. development. Increased

secondary and tertiary recovery must also be explored as alternatives to expanded O.C.S. development.

6. Shortages of manpower and materials may prevent O.C.S. development within the proposed time frame. O.C.S. leasing should not be accelerated at a more rapid rate than industry can responsibly develop the lease areas.
7. We do not have sufficient data regarding our marine and coastal resources, and the potential impact of O.C.S. development on those resources. Studies providing the necessary data should be conducted prior to any decision being made regarding expanded O.C.S. development.
8. The relative environmental impact of drilling in various O.C.S. areas must be considered prior to any decision regarding expanded O.C.S. development.
9. The air quality impact and land use impact of expanded O.C.S. development and the growth induced by that development have not been adequately analyzed.
10. The economic and environmental consequences of O.C.S. development are not fully understood. To better understand the potential impact of O.C.S. development, attention should be given to experiences such as the aftermath of the 1969 Santa Barbara oil spill.
11. As a result of O.C.S. development, land values may diminish.
12. The public should be compensated for diminution of property values, loss of marine and recreational

resources resulting from O.C.S. development. Local government should be compensated for the cost of providing services to growth induced by O.C.S. development to the extent it is not offset by increased revenues.

13. Mitigating measures such as drilling farther offshore, more stringent regulation, subsea completion and camouflaging rigs must be considered.

14. The present bonus-royalty leasing system may be anti-competitive and fail to assure that the people receive a fair return for sale of their natural resources. Alternative leasing systems should be examined.

15. For the Department of the Interior to proceed with O.C.S. development prior to completion by impacted states of coastal management plans would result in circumventing the purposes of the 1972 Coastal Zone Management Act.

We urge the Department of the Interior to prepare, circulate, and consider a new draft E.I.S., giving careful attention to the issues raised in this Analysis.

SECTION II

THE SCIENTIFIC ADVISORY COMMITTEE ANALYSIS

SECTION II

Scientific Advisory Committee Reports

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Although not all members of the Scientific Advisory Committee contributed written reports for inclusion in this Analysis, their assistance has proved invaluable in preparation of this document.

ACKNOWLEDGMENT

The material prepared by Robert Lutz and Lawrence Leopold on the impact of O.C.S. development on land use was incorporated into Part III, L of Section I of this Analysis. We wish to express our appreciation to them for sharing with us their knowledge of coastal zone management.

A Critique of the Consideration of Air Quality Within the Draft Environmental Statement for the Proposed Increase in Acreage to be Offerred for Oil and Gas Leasing on the Outer Continental Shelf

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Standard for Evaluation

This draft Programmatic Environmental Statement (DPES) has been reviewed noting that it calls for an approximate tripling of OCS acreage to be leased over that leased in prior years. To do so will require dedication of substantial material, human and economic resources to peripheral activities without which OCS leasing would be fruitless. The review also has been undertaken within this layman's understanding of the spirit of the national Environmental Policy Act -- a full and complete disclosure of fact so that decisions made do not lead by increments to unnecessarily destructive consequences; consequences which we might have chosen to avoid given reasonable warning.

Scope of Concern

The review has been directed primarily toward those consequences which would follow for the Los Angeles Metropolitan Air Quality Control Region. However, to export Southern California problems to another region would not be equitable. Thus implicit in the thinking behind any statement is equal concern for similar problems of other regions.

What Does the DPES Say Regarding Air Quality?

The DPES is both brief and specific regarding air quality. On pages variously numbered 104 and 110 of Volume II statements are made as follows: "In terms of air quality problems along the Pacific Coast Zone the only significant areas are located in Southern California, particularly in the Los Angeles Metropolitan Area. The other areas have minor problems which are not considered to be significant." Additional very brief discussion of air quality impacts is included on pages 260 to 262 (or 266 to 268). This discussion relates to emissions from exhausts

of stationary power units and service vessels, the accidental release of oil and gas from wells which are out of control, and changes due to possible increases in refinery capacity.

To place these statements in perspective, consider that the entire State of California, not just the Los Angeles metropolitan area, has committed itself to tougher automobile emission standards than those used nationwide. This has been done at added cost measured in many tens to hundreds of dollars per vehicle, and with reduced gasoline mileage. Air pollution is a problem recognized by those who live in the San Francisco Bay area and parts of the San Joaquin Valley as well as Los Angeles. Thus statements which convey the impression of a disclaimer are not appropriate. Furthermore, the lack of concern suggested is particularly surprising when with proper design of the OCS development program and facilities, improvements in air quality could result. The handling of this very important problem suggests predisposition toward a final result. It does not suggest careful evaluation seeking an optimal path toward an optimal result within an admittedly complex situation.

Impacts Related to Routine OCS Operations

The Western Oil and Gas Association (WOGA) has moved to preempt the field with its "Environmental Assessment Study: Proposed Sale of Federal Oil and Gas Leases, Southern California Outer Continental Shelf" (October 1974). Appendix 2 uses data and simplified modeling to detail probable air quality impacts on the coastal zone from the engines, etc., used in routine operations. The conclusions appear sound and could be anticipated: routine OCS operations would be well enough spread out and would involve small enough emissions to not adversely effect urban air quality. Perhaps for

this reason the rather casual treatment in the DPES almost appears to be justified.

Impacts Related to Uncontrolled Well Operations

Even the best-engineered petroleum operations occasionally get out of control with release of vastly increased emissions to the atmosphere. (A gas well burning out of control in the San Fernando Valley of Los Angeles as this is written provides an example.) Just as wildfires in foliage-covered urban-adjacent areas can cause severe air pollutant emissions for a period, so could a near-shore OCS spill, fire or similar incident.

This fact is recognized in the DPES. However, the brief, offhand discussion suggests a lack of concern for the possible chains of subsequent events. True, air pollution consequences at the time of an incident may seem minor, but only because even more annoying and equally visible signs of man's failure are present. Thus lack of concern should not exist.

There is a well-developed body of knowledge from an even more environmentally sensitive area transferrable to this situation. WASH-1400, entitled "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," (U.S. AEC, August 1974), provides a summary of the well-developed techniques by which to analyze the possible event trees following some initial equipment or personnel failure. Furthermore, aerospace large-system management procedures can be utilized to avoid mishaps within OCS operations ("Applicability of NASA Contract Quality Management and Failure Mode Effect Analysis Procedures to the USGS Outer Continental Shelf Oil and Gas Lease Management Program," USGS, November 1971). Unfortunately, the DPES shows little evidence that this available knowledge

has trickled down to working levels where "policy" actually is carried out.

It is most unfortunate even at this state of decision-making to read statements such as "there is no reliable way to predict in advance the relative volumes of each of these possible emissions ....." These words should be replaced at least with references to well-established and appropriate kinds of analysis. The planning process then can in part include establishing priorities for lease areas on the basis of minimum risk.

Impact of Refinery Expansion

It is admittedly not possible to project what Southern California refinery expansion may or may not accompany OCS oil development. There are too many alternative ways to provide the capacity needed. Estimates of Southern California production range to 1,000,000 barrels per day (WOGA "Environmental Assessment"). A likely sustained level if the resource proves out might be 700,000 barrels per day. Estimates are that natural gas at a gas-oil ratio near 2,000 cubic feet per barrel will accompany this oil, totalling perhaps 1,300,000,000 cubic feet per day. In addition, one should consider during the same time frame up to 300,000 barrels per day of oil from Elk Hills, gradually declining production from the rest of California, and up to 2,000,000 from Alaska. Gas production will accompany each source. Even if refinery locations cannot be specified at this time, several consequences are certain. Either this large quantity of oil will be refined at one of a very few locations on the Pacific Coast, it will be pipelined to the east, or it will be sold on world markets. The decision on refinery expansion is a critical one. It is highly undesirable to leave this in a nebulous state because a wrong decision

could have important consequences.

The 1970 crude capacity of Los Angeles refineries was about 918,000 barrels per stream day (Oil and Gas Journal, April 1970). The 1972 emissions from these refineries were credited in tons per day about as follows: particulates, 3; SO_2, 60; NO_x, 67.5; reactive hydrocarbons,7.0; and CO 2.0. (Information gathered from local APCD's, the California Air Resources Board and the EPA.) But some of these data currently are recognized as an underestimate of emissions from refinery sources. Under Air Resources Board sponsorship, KVB Engineering, Inc., has tested refinery units and found NO_x emissions to be as much as twice the Los Angeles APCD reference values, for example. (A copy of the newly released report on this work is still in transit to us, so I am unable to give a precise reference at this time. Results have been discussed by telephone only.) Probably estimates of emissions should be 100 tons per day of NO_x from boilers and other heating units within refineries. This is an important quantity of a noxious pollutant which should and can be reduced. Furthermore, SO_x and sulfate emissions may pose a much greater risk than NO_x.

The air quality problem in Southern California is serious. Furthermore, the location of refineries within the air basin is such as to have an important air pollution impact. Thus on the basis of present projections, probably no additional refining capacity should be permitted in the Los Angeles Air Quality Control Region. Before any change from such a prohibition is considered, detailed emissions inventories should be established for the projected configurations. Analysis and tracer studies should establish that the projected expansion will not prevent meeting all federal and state laws, and a monitoring system to ensure compliance should

be established. At least the need for such thorogh evaluation should be noted at preparation of the DPES. If such plans are not laid prior to accelerated leasing, convenient development of oil and conventional internal costs are likely to control all siting efforts.

A quantitative measure of the value of siting any refinery expansion outside critical air quality regions can be shown as follows. Suppose Los Angeles' refineries approximately double capacity to meet "demand." Even with improved refinery NO_x control, emissions will increase by about 70 tons per day. To achieve an equal reduction from another large source, the automobile, would require meeting about a 0.4 gram per mile tougher NO_x emissions standard than otherwise planned (vehicle miles travelled estimates based on "State of California Transportation Control Plan for the Metropolitan Los Angeles Instrastate Air Quality Control Region" November 1974.) While this can be done, it probably would cost an additional 10 to 15% drop in gas mileage. Thus control at the refinery source, including proper siting, is much preferred.

Impact of Natural Gas Availability

There is one strongly beneficial air quality impact of particular importance to Southern California. Natural gas produced along with oil is a clean fuel in very short supply. The quantitites under consideration range up to 1.3×10^9 cubic feet per day or about 1.3×10^{12} Btu per day heating value. This closely approaches 1972-73 utility boiler needs. If available, it would permit perhaps a reduction of 105 tons per day in NO_x emissions, and substantial decreases in SO_x emissions and sulfates as well. But to utilize this valuable and non-renewable resource in the best way requires advance planning rather than just sale at some currently highest price. This should be recognized at the earliest possible stage of decision-making, the DPES.

ADDITIONAL COMMENTS ON THE DRAFT E.I.S.
AS IT RELATES TO AIR QUALITY

By

Dr. Alan C. Lloyd

Statewide Air Pollution Research Center,
University of California at Riverside

Additional Comments on the Draft Environmental Statement - Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf by the Statewide Air Pollution Research Center, University of California, Riverside

We reinforce the pertinent comments presented by Dr. Richard Perrine. In particular, we feel that not sufficient attention has been given to the possible impact on air quality of any increased oil refining load which may result from the increased oil production. This is not adequately addressed in the Draft Environmental Statement (DES) and subsequent comments are based on the ramifications of any significant increased air pollutant burden in the Los Angeles basin.

Because of the location of exploration and oil refining operation - at the western end of the Los Angeles basin - any increased air pollutant emissions will affect the downwind areas, not only in Los Angeles County, but also the South Coast Air Basin (SCAB) which extends to Riverside and San Bernardino. The DES does not address itself to the possible implications for these downwind areas.

At least three major pollutant categories have to be considered in connection with the DES - hydrocarbons, nitrogen oxides and sulfur oxides. Hydrocarbons, along with nitrogen oxides, are the main precursors to photochemical oxidant production. Because the SCAB is already plagued by oxidant levels which exceed the federal air quality standard for a large majority of the time, during the spring, summer and fall, any major increase in hydrocarbons is clearly unacceptable.

The recent report prepared by KVB Company (September, 1974) for the California Air Resources Board shows that the nitrogen oxides (NO_x) emissions from oil refineries in the coastal areas of the SCAB are already substantially underestimated and that the petroleum industry is the second largest stationary source emitter of NO_x in the SCAB. As indicated above, not only is NO_x a precursor to photochemical oxidant formation, but it contributes to nitrate formation which has

been shown to be a major contributor to visibility reduction, particularly in the eastern area of the SCAB. In addition, many nitrogenous compounds, such as peroxyacetyl nitrate (PAN) are powerful phytotoxicants.

Finally, with the continuing energy crisis and with the likelihood of increased use of high sulfur fuels, any significant increase in emissions of sulfur oxides (SO_x) could have major adverse effects on the health and welfare of the residents of the SCAB when these emissions are added to the existing oxidant burden. Increased SO_x emissions further compounds the problem brought out in the recent disclosure that catalyst equipped automobiles emit significant amounts of sulfuric acid mist which may be a threat to health.

In summary, the impact on air quality in the areas delineated above, resulting from any proposed actions, should be clearly delineated in the DES. This is not the case currently. Parenthetically, emphasis in this or any other project should be one of creating a clean operation--not one of "exporting" the problem to some other areas. If we're going to use petroleum products we will need wells and refineries. Dirty wells and refineries are undesirable anywhere--inland, desert or mountains, etc. Designing new facilities offers the best opportunity to make clean operations.

EVALUATION OF THE DRAFT E.I.S.

AS IT RELATES TO MARINE BIOLOGY-VERTEBRATES

by

Dr. Malcolm S. Gordon

Professor of Biology

University of California at Los Angeles

Evaluation of portions of draft Environmental Statement (No. DES 74-90) prepared by the Bureau of Land Management, U.S. Department of the Interior, entitled "Proposed increase in acreage to be offered for oil and gas leasing on the Outer Continental Shelf." Portions evaluated relate to living marine animals, especially vertebrates, in the affected areas off southern California.

by

Malcolm S. Gordon

Professor of Biology and Director, Institute of Evolutionary and Environmental Biology, University of California, Los Angeles.

This report continues the evaluation of the subject DES begun by the author in the accompanying report on marine invertebrates. This report relates to marine vertebrates, including fishes, birds and mammals. It is structured in parallel to the report on invertebrates.

1) Scientific accuracy of the DES:

The general comments made in the report on invertebrates apply equally strongly to the vertebrate sections. The specific sections of the DES including materials relating to vertebrates are the same as those listed in the invertebrate report.

As was the case with respect to the invertebrates, the DES draws several questionable conclusions concerning likely impacts of oil and gas development on marine vertebrates. For example:

On p. 173, vol. II (section III B1), the statement is made with respect to nektonic animals (nekton are animals large

enough and strong enough to swim actively under their own power for significant distances): "Therefore, the only significant impact on the nekton would be as a result of a massive oil spill which they cannot quickly avoid."

This is incorrect on several grounds. While a massive oil spill might be one of the few ways in which oil and gas development could cause rapid disability or death in many adult nektonic animals, especially fishes, this is not the case with respect to the young of many of these forms. Nektonic fishes frequently have surface layer dwelling, pelagic eggs, larvae and juveniles, and often form important parts of the zooplankton populations of large oceanic regions. These pelagic stages can be directly affected by low level, long term exposures to small amounts of oil components, as can other planktonic organisms. Since these young stages are generally predatory and feed almost exclusively on other zooplankton organisms, they are also very likely to be excellent candidates for the effects of biological magnification of low level environmental concentrations of contaminants. It thus seems probable that the longer term, somewhat indirect effects of low level oil and other waste contaminants will be far more important and widespread for OCS populations of nektonic organisms than will the direct effects of large spills on adult animals.

The statement is somewhat more accurate with respect to birds and mammals (in fairness I must note that the DES comments on aspects of the following points in section III blc).

However, these animals almost all occupy positions in their respective food chains that are quite high up (they are often third or fourth level predators). Thus, just as has been shown to be the case with respect to DDT (the accumulation of which in the food chain produced catastrophic bad effects on breeding capacities of California brown pelicans), it is probable that the birds and mammals of the southern California OCS will be on the receiving end of greatly magnified concentrations of oil and other contaminants in their food. The effects these exposures, and probable body accumulations, will have are uncertain or unknown. However, they are likely to be seriously deleterious to the well-being of these forms.

Section III E 1 (DES vol. II, pp. 266-268) also reaches a questionable conclusion: "In summary, oil spills present the greatest potential hazard to commercial fish and shellfish." The same points apply here as have just been made. However, the conclusion is all the more curious because the text of the section leading to this conclusion is substantially devoted to a literature summary which largely supports the points I made in the preceding paragraphs of this report.

The DES is inadequate and incomplete in its assessment of possible impacts of OCS development on economically important fisheries resources in southern California. The entire emphasis is on commercial fisheries, with practically no consideration given to recreational fisheries (cf. sections VE and H, vol. II of the DES). The latter differ in major ways from the former and, in southern California OCS waters, are probably even more

valuable than the former. The entire discussion of possible fisheries impacts is strongly influenced by Gulf of Mexico experience. For reasons discussed in my report on invertebrates, this is unlikely to be widely applicable to southern California situations.

The DES is completely silent on possible impacts on the recreational values of the marine bird and mammal resources of the southern California OCS. Both bird and mammal watching are very popular in our area, the mammal watching being primarily centered upon migratory gray whales. In terms of numbers of people involved, time spent, and dollars spent during a year, I suspect that shore and sea bird watching are the largest scale activities.

2) Gaps in the scientific data contained in the subject DES; and

3) Recommendations for studies needed to permit writing of a fully adequate final EIS, with an estimate of how long such studies would take.

Here again this report parallels the accompanying report on invertebrates. For the same reasons cited in the invertebrate report, and with the same recommendation for its inclusion as part of this report, I append a copy of the workshop report on marine vertebrates which resulted from the Southern California Academy of Sciences conference on board the "Queen Mary" in December 1974. This workshop report was written by Professor Kenneth S. Norris from the University of California, Santa Cruz.

I will make two remarks concerning this workshop report: First, I believe it does not fully adequately emphasize the need for further work on fishes, especially studies of their ecological dynamics (see invertebrate workshop report for parallel studies). Second, I believe it significantly underestimates probable dollar costs of the studies outlined.

Recommendations for

Vertebrate Surveys

Among the most sensitive aspects of the marine environment with regard to impaction by offshore oil drilling, its associated activities and with possible oil spills are the vertebrates, i.e. marine mammals, birds and fishes.

In the southern California bight are major populations of all forms. In fact the area is unquestionably the most important ocean segment on the Pacific coast of continental US with regard to animals. The largest seal, sea lion and sea elephant populations on the Pacific coast occur in the area, including major breeding grounds. Birds and bird breeding grounds are likewise numerous, as are those of reef and benthic fish. Seven species of baleen whales, and 24 species of porpoise and toothed whales occupy the area, and include major populations, breeding grounds and hundreds of thousands of individuals. All major migratory paths of large marine mammals appear to pass through the area.

Also, it is fair to say that public concern about these animals and their treatment at the hand of man is second to none. Kills or injury to porpoises, whales, seals, sea lions, birds or fishes can all be expected to rouse great public indignation. There are also true causes for concern. Birds are particularly susceptible and quickly succumb if wetted

*:by Kenneith S. Norris, Director, Coastal Science Laboratory, University of California, Santa Cruz; Chairman of Workshop on Biological Oceanography (Section on Vertebrates), Southern California Academy of Sciences Conference, Queen Mary Conference Facility, Long Beach, California, December 6, 1974.

with oil. The effect on seals, sea lions, porpoises and whales is harder to assess but nevertheless of concern for several reasons, such as inhalation of oil, concentrations on breeding grounds and so forth. Nearshore fishes, especially, and benthic forms are also susceptible, because their habitat may become a repository for oil. Hence accurate estimates of normal populations and their movements are vitally important.

How may it be achieved? An integrated set of surveys and sampling and tracking efforts is called for. These must be combined with an appropriate data acquisition, interpretation and storage program and with coordination functions with other baseline activities such as oceanographic surveys.

To put this more specifically let us look first at the needs, and second at the means we see for development of a baseline of information.

First, surveys of abundance and distribution are needed. How many animals are there and where do they live? Aerial surveys can be combined for marine mammals and birds and should include a transect survey and regular overflights of pinniped rookeries (seals, sea lions, etc.) and bird colonies. Reef fish must be surveyed by divers to determine indices of diversity and abundance at various critical localities throughout the area of concern. Benthic fish should be sampled probably by trawl and traps.

It was concluded that in the time allotted, no meaningful

additions to information already existing in the records of the California Fish and Game and CalCOFI could be gathered concerning midwater fishes or fish larvae, but instead these long-standing records should themselves constitute a baseline.

Let's look at the individual efforts needed.

Aerial Surveys

A once monthly Gate Line Transect is needed using for safety a twin-engine aircraft (Helios, Skymaster, Supergoose or Bronco preferred) and strut or belly-mounted aerial camera assemblage. This should be run at lo minutes of latitude intervals from shore to on the average of 100 miles offshore from lat. 32° 30' N to Pt. Concepcion.

These flights should run at days of choice, depending upon weather, and normally should run from 8 AM to about 1 PM because of sun angle and wind.

The aircraft should fly at about 600-800 ft. altitude, should photograph each bird flock, pinniped or cetacean school, record the exact locality using a direct readout radio fix method. When a school or flock is sighted, the plane will deviate for photographs but return to the track line and continue to allow statistical analysis. Three observers should be used; two sighting, one from each side of the aircraft, and one note-taking and providing fixes and serving as a reserve to replace tiring observers.

Observations and photographs should be analyzed and coded

by geographic coordinates for each machine correlation and data retrieval.

It probably will be possible to identify most cetaceans and pinnipeds to species with experienced observers and interpreters. Birds may be identified in some cases to species but more often to genus or families. It should be noted that such data are almost nonexistent for birds.

Data should be broken down as to school or flock size, locality shape (feeding or travelling aggregation, resting or moving group, etc.), time of day and species compositions.

Pinniped and bird surveys require that haul out nesting and rookery grounds be overflown and photographed regularly. In these cases counts of individual animals will be made and data on groupings within these aggregating animals made insofar as is possible.

Shi Operations

Two rather different sorts of ship operations are needed. First, ground truth (or "water truth") for flights is needed. Cross checks must be obtained concerning (a) species identification from the air, (b) sighting frequency of bird flocks or marine mammal schools, (c) numbers of animals reported, and (d) correlation with marked animals obtained.

The other sort of ship activity that is needed concerns the capture, tagging, stomach analysis, and tracking of animals. Because capture of marine mammals and birds

requires great persistence and cannot be at the beck and call of an overflight schedule, this collecting vessel will have to operate on its own schedule determired by weather and availability of animals. Because any such handling of animals requires approval of the Marine Mammal Commission, the crew willl have to be experienced and accredited and will have to operate under an appropriate permit.

This ship will catch, salvage (obtain stomach samples by nonharmful means for food and parasite analysis), freeze brand, place dorsal fin roto tags (which have been tested to nearly 3 years in wild porpoises), and release the animals concerned. Some animals will be equipped with dorsal fin or harnessed radio tags for long-term (to 6 months) radio tracking. These will be chosen from species of special importance to be tracked both by boat and air. Radio tracking allows localization by air over long periods and hence is a uniquely important method. A few such tags will return essential data at many times the rate of visual tags that have to be sighted at sea, since radio tracking by air is possible.

Nonetheless, visual tags are of great importance too! We suggest four kinds; the plastic dorsal fin roto tags for porpoises and whales that are punched in with a pair of special pliers, freeze brand, dying for birds, and spaghetti tags. Laser branding will be used if available for marine mammals; it is presently in development at the UC Santa Cruz lab. Roto tags may migrate out of a fin, and the loss rate is unknown

to us. To validate tagging and to estimate this rate, each roto-tagged animal will also be freeze branded. Freeze brands scar white and are easily visible, perhaps even by air. In any case freeze brands allow a crosscheck on loss of dorsal fin tags.

Spaghetti tags are long plastic streamers held in place by a dart. These can be placed by hand harpoon or crossbow and allow placement of many tags in a short time.

Both roto tags and spaghetti tags should be color coded by area to allow rapid visual assessment from shipboard of the place of origin.

Such ship work allows assessment of immigration and emigration from the area, and will allow identification of some schools from the air.

Similar tracking of birds from rookeries by radio will allow identifications and location of feeding grounds. Birds should also be dyed in the next to identify source nesting groups and to allow identification at sea.

Data Acquisition & Interpretation

All data must be computor compatible. Data gathering programs should be designed in acquisition and accession to allow retrieval of cross correlations by geographic coordinate, species, time of year, time of day and size of group. Transects should be correlated where possible, with CalCOFI stations.

Citizen Participation

Considerable reservoirs of skillful and interested lay observers exist in the southern California area. While, for marine mammals we recommend the use of highly trained professionals, because security of identifications is often difficult for many species, such groups might be invited to submit plans for work on certain species; for example, they might describe the passage of certain migratory species such as the gray whale, the humpback whale and the killer whale. Similar contributions for the bird program might come from the Audubon Society, who have many members of excellent observational capability

Kelp & Benthic Fish Populations

The evaluation and status of both kelp and benthic fishes is very important. In order to discern subtle changes, long-term surveys are needed, requiring cross correlations of both island and mainland communities. The assessment of benthic communities is particularly important at the proposed drilling sites. The assessment scheme should be designed in such a manner that it is easily integrated with CalCOFI, California Fish and Game and NMFS survey data.

If funds allow, many important questions that require experimental work, especially that dealing with human-related effects upon the food web, are to be encouraged. Much, for example, could be gained by studies of the effects of oil on rookeries, on food webs, and on the behavior and on the physiology of benthic fishes.

Bird Breeding Colony Studies

For each colony, enumeration of nesting birds should be accomplished by aerial censusing of nests or breeding pairs, depending upon the habits of each species. In addition ground based surveys of accessible colonies should be conducted in order to validate aerial censuses. Data gathered prior to the baseline study should be incorporated in order to determine historical trends.

Since reproductive success of colonial seabirds is sensitive to environmental quality, it is essential to measure reproductive success in representative colonies at several times within a breeding season in order to determine the number of young raised per pair and, if reproductive failure is found, to determine at what stage it occurs. This information will be needed, in event of an accident, for separating reproductive failure related to an accident from failure due to pre-existing conditions. Measures of hatching failure, chick mortality, and residues of DDE, PCB and petroleum hydrocarbons should be obtained.

Do sea birds congregate in particular ? To
what extent do local breeding stocks intermingle at sea? These questions are all relevant to predicting the effects of seabed exploitation upon reproductive success of local breeding populations and can only be answered through studies of the activities of marked individuals of known colony affinities.

These questions can be approached in two ways. First a number of adult and immature birds can be color-marked at selected breeding colonies. Marks should be highly visible and relatively permanent. Observations of marked birds could be conducted in the course of the regular offshore censusing scheme described above, thereby yielding gross information on concentrations of marked birds and their interactions with other species. Land-based observers should also endeavor to locate marked individuals as they forage close to the breeding islands.

Second, to provide detailed information about movements of breeding birds, one could radio tag and track small numbers of adults of various species in and around the breeding colonies. This is a relatively low-cost technique that could provide detail of the sort that is not usually accessible through the use of visual tags and stationary or shipboard observers due to rapid, long-distance movements of marked subjects. Radio-tagged individuals can be followed over relatively large distances with a minimal investment of ship

and observer time. The location of telemetry subjects can be evaluated by triangulation using one stationary and one shipboard receiver. All necessary telemetry gear is available commercially at present.

Beached Animal Surveys

The collection of beached cetaceans, pinnipeds and sea-birds has proven to be an indication of the health of populations. For instance, in the event of an oil spill, the numbers of oiled birds deposited on a beach can be great, and may provide an index of mortality. However, such information is of little validity if there is no information on the "normal" number of animals washed ashore when there is no spill involved. Thus, it is essential to survey on a monthly basis selected stretches of mainland and island shoreline for the enumeration of beached animals.

Causes of death and parasite loads can be approached by sampling such dead animals and is recommended.

Specimen Repository

It is recommended that a central site be identified as a repository for stranding samples, probably the Los Angeles County Museum. In this way important aspects of the baseline may be preserved in case comparison is needed.

Time & Timing

All participants agree that replicated efforts are needed, since all features that will be determined are in some degree

of continual flux. Nonetheless, much can be gained in a single effort. General outlines of distribution and much more precise ideas of numbers than now exist will result.

However, even the roughest idea of variability is of great value and thus we hope that a minimum 3-5 year plan can be contemplated.

Schedules should be arranged to take optimum advantage of breeding periods, especially for birds and pinnipeds.

Several permits will be required, so early designation of contractors and applications are crucial.

Budget

While it is not possible at this time to give precise budgets, estimates are possible.

Marine Mammal Programs	
Joint Aerial Surveys	$250,000
Bird Programs	100,000
Reef Fish Programs	25,000
Citizen Effort	15,000
Sample Repository	15,000
Benthic Fish Survey	100,000
est.	$605,000/year

EVALUATION OF E.I.S. AS IT RELATES TO MARINE BIOLOGY-INVERTEBRATES

Dr. James G. Morin
Department of Biology
University of California at Los Angeles

January 24, 1975

TO: The City of Los Angeles,
Mayor Tom Bradley and City Attorney Burt Pines

FROM: Dr. James G. Morin
Department of Biology
University of California
Los Angeles, California

RE: Evaluation of the southern California marine invertebrate sections of the Bureau of Land Management's Draft Environmental Statement "Proposed increase in acreage to be offered for oil and gas leasing on the outer continental shelf" (DES 74-90).

I have been requested by the City of Los Angeles to evaluate, with respect to southern California marine invertebrate zoology, the overall accuracy and thoroughness of the Bureau of Land Management's (BLM) Outer Continental Shelf (OCS) Draft Environmental Statement (DES) numbered DES 74-90. I was also asked to indicate areas of further study and a possible time table.

My basic evaluations are:

1) The data presented in the DES, as far as they go and with some exceptions, are accurate.

2) The DES makes no claim to being complete (Vol 1, pp 14-16). However, I feel this report shows a lack of inquiry into the available literature to the point that essential information has been excluded.

3) In assessing the possible affects of normal drilling activities and accidental spills on marine communities, the report does not consider recent predictive and theoretical research into the structure of marine communities.

The DES represents a prodigious, but clearly not comprehensive report. Considering the massive scope of the report it is not surprising that a fair degree of completeness had to be sacrificed. I especially feel that the sections dealing with the biological aspects are generally vague and deficient. Therefore, the remainder of my report will focus only upon the organismic and ecological aspects of the DES as they relate to the marine invertebrates of the west coast and specifically to southern California.

1) Accuracy and 2) Completeness of the DES.

The data presented in the DES, as far as they go and with some exceptions, are accurate. But there are fundamental short comings. These include imprecision, incompleteness and faulty interpretations.

One imprecision that I encountered was in distinguishing what was considered offshore environment (section IIA) and the nearshore environment (section IIB). The net result seemed to be to consider the nearshore marine environments, with respect to benthic communities, to be only 1) the intertidal and 2) bays and estuaries (Vol. II, pp 2-12). On the other hand and although it was not specified, the offshore environments were vaguely discussed in terms of 1) the "nearshore area" (from shore to approximately 300 feet) and 2) the deep areas of basins, troughs and submarine canyons (Vol. I pp 434-440). This distinction is very important and the shallow benthic (and planktonic) communities are significantly different from deep communities. I would suggest that, until more precise data are available, the 300 foot level be used as a convenient line of demarcation between nearshore (or shallow) and offshore (or deep) areas.

With respect to the biological materials, I consider that an inadequate general survey was made. The bibliography lists only a few governmental reports, some old surveys and a general ecology text. Much new and relevant material has since appeared which largely supercedes or modifies these sources. In recent years, along with long term purely scientific research, a considerable number of governmental agencies (particularly state and local) and private companies (PG and E, Edison, etc.) have either begun studies themselves or contracted with consulting firms to evaluate various aspects of the quality (and quantity) of the marine environment in southern California. Thus, contrary to indications from the DES, there has been a tangible amount of information which is publicly available concerning the O.C.S. of southern California. I include a bibliography of some potentially useful recent references. Even with such information I still consider the available information to be inadequate in order to thoroughly evaluate the impact of the intended leases. Direct sampling and research will be required before final decisions should be reached.

While the deep regions remain relatively poorly studied, the shallow sectors are becoming relatively well known even though the DES devotes but

two pages to this region (from the middle of page 435 to the middle of page 437). Included within the boundaries of this region are our ecologically and economically important extensive kelp beds which overlie immense stretches of rock reefs. These kelp forests and their accompanying reefs are some of the most productive and ecologically significant habitats in the world. They support a productive fishery for fish and shellfish. The DES report ignores the kelp beds entirely in this section and further states that "rocky outcrops on the continental shelf in this area are relatively uncommon." (I refer you to the report of Dr. Chapman for particular consideration of the kelp bed aspects of the report). Clearly the report has overlooked some important habitats within the southern California OCS.

Throughout the report it is either implicite or implied that "the duration of the impact [from construction and spills], will be short, with recolonization being completed within a year or two" (Vol. II, p. 180). My own belief is that benthic communities may suffer long term detrimental effects from any aspect of the drilling operation but more importantly from spills, whether they be major or minor. Most of the spills that have been analyzed with respect to shallow benthic destruction have stressed the amount of depopulation and subsequent recovery with respect to total numbers or biomass and without respect to all of the members of the community or to former community structure. What has been shown in these studies is that, in areas of extensive spill damage, the members of the community which have a rapid life cycle and rapid rate of growth recover very quickly by larval recruitment from unaffected areas. However, it is often the long lived organisms, (whether they be primary producers, suspension feeders, predators, etc.) that exert a major influence upon the final stable community structure of a given habitat (Paine 1966, 1971, 1974; Dayton 1971; Porter, 1972). Thus, while there is the superficial appearance of a rapid community recovery, it is very probably illusory and may represent only the initial stages of a succession that may take many years to regain the former stability. Many of these long lived organisms which I referred to above are sessile or sedentary and, therefore, cannot escape a spill. Fishes and the larger crustaceans may be able to escape a local spill via their mobility.

Such long term adverse effects could be expected for any benthic community, be they hard substrate (rock, piling, etc.) or soft (sand, mud, etc.).

shallow or deep. The kelp forest is a particularly vulnerable and delicate environment where some of the most elaborate inter-relationships known on earth occur. Another habitat, one which I have been carrying out basic ecological research on for five years. is the shallow subtidal (10 to 50 ft.) sand habitat. I will use it as an example. Of this type of habitat the DES report states "sandy areas in depths of 10 to 30 feet are relatively harsh environments due to an unstable bottom which shifts because of wave action. The number of individuals is not significantly lower in comparison with the deeper bottoms, however. [It is in fact significantly higher] The types that have adapted to the shifting sands include those that occupy transient or relatively permanent deep burrows, . . . " (Vol. I p. 437). While it is true that the sand bottom is a harsh habitat. the shallow sand is not depauperate but represents an extremely important community. Merril, and Hobson (1970) have shown quite conclusively that a large number of our California beaches are dominated by enormous numbers of the sand dollar Dendraster excentricus in depths of 10-50! The densities of these organisms can reach as high as over 1,200 per square meter (each individual averages about 2-2 1/2 inches in diameter). They clearly dominate the whole region and almost certainly provide the largest biomass within any sand to mud habitat from the intertidal to the deepest basins within the southern California OCS. The sand dollar is a suspension feeder which eats mainly living microscopic phytoplankton, (contrary to what is implied within the DES for most benthic animals Vol. 1, p. 435). Furthermore, I have found (Morin et.al. in preparation, as well as Merrill and Hobson, 1970) that the sand dollar bed lies within a distinct zone and that certain organisms form an association with the sand dollars such that the community on either side of the sand dollar bed is different from that within the bed. Elimination of the sand dollar population as a result of an oil spill or other catastrophe would drastically alter the whole shallow sand community structure. These changes almost certainly would not be short term. The average age of the sand dollar population we are studying is 9 years and they live as long as 13 years. It takes several years to attain sexual maturity. Thus restoration of a viable sand dollar bed and its associated community elements would undoubtably take several years. Furthermore, the dominant organisms (these include the Pismo clam, Tivela stultorum, the sea pansy, Renilla Kolliker:, the sea pen, Stylatula elongata, and the sand stars Astropecten

armatus and A. californicus) in the areas around the sand dollar bed are also fairly long lived animals (three to forty years depending on the species) so that their demise might further affect the community structure following a catastrophe. The effects that the absence of all of these dominant, long lived organisms would have on the overall structure and productivity of the area cannot be predicted at this point in time, but it almost certainly would be negative and substantial.

For rocky habitats in other parts of the world which are comparable to our own, such as Washington state, there are some data which demonstrate the effects of removal of long lived dominant members of the community (Paine, 1966, 1974, Dayton, 1971). These results indicate that the dominant members have a dramatic effect with respect to diversity and abundances.

There are no comparable data for any of our OCS deep benthic communities. We do know that at least some of the epifauna are long lived (eg. some of the sea pens) and, on the basis of abyssal bottom studies, we know they are usually very stable (Dayton and Hessler, 1972, Sanders, et.al., 1965) The deep sea is also very cold, being only a few degrees above 0°C. Dayton et.al. (1970,1974) have studied what appears to be a somewhat comparable shallow water rock and mud bottom community in the Antarctic and have found that growth, predation, competition, etc. are extremely slow in these cold waters. Perturbations in those communities affect them for years. If this antarctic region is found to be comparable to the deep benthos, then we would expect that a damaged deep water community might not recover for many years. Damage to these communities would come primarily from dumping of the drilling muds, other construction materials and perhaps from entrapped oils from bottom blowouts. The extent of these deep sea communities is probably very large and hence local dumping would probably effect only a fraction of the community. However, we do not know enough about this region to be able to adequately predict the results of such activities.

Not only might recovery from damage be slow in all of the above mentioned areas, but also the community that appears after recovery need not be the same as what was there prior to the alteration. Recent experimental evidence has shown that a community can have an exceedingly different structure at stable equilibrium depending on the prior history of that habitat (Sutherland, 1974). That is, the stable community that finally develops in a habitat following major (or even perhaps minor) destruction [by an oil spill (or

mud or other dumping, etc.)] will not necessarily be at all the same as what existed before.

Of additional concern not specified in the DES should be the consideration of deleterious, sublethal affects of oil spills and other related oil activity on the physiology and behavior of community members. The results may be similar to total destruction of a species as described above. Similarly there is the potential for synergistic effects between oil related effluents and other pollutants (such as sewage). Thus, while each alone demonstrates little or no effect, together they might show serious alterations within benthic or planktonic communities.

Furthermore, it is evident that man's activities in the southern California area have substantially effected the overall quality of our local biota (Fay, 1972 a,b). Much work is now being done by many sectors to attempt to correct or alleviate these problems. It seems to me that we should be exceedingly cautious in expanding similar potential hazards to even more distant areas than have already been effected.

Therefore, to summarize what should have been done to eliminate the ambiguities and incompleteness: First and foremost, the DES shows a real lack of inquiry into the available literature to the point that essential information has been excluded. I would suggest that before the DES is finalized there should be 1) a careful consideration of the available literature, 2) a close liaison with local, state and private agencies which have much information held in public trust, 3) a careful comparison of local community structure with similar more thoroughly studied ones elsewhere, and 4) a serious evaluation of recent predictive and theoretical ecological findings on marine communities in order to provide possible clues to what might be relevant for our local waters.

3) Additional studies and time estimates

Extensive studies must be undertaken to thoroughly evaluate the potential lease sites with respect to the benthic and planktonic communities present. These communities should be assessed with respect to 1) their distributions (unique and restricted to cosmopolitan), 2) their stucture (ecological inter-relationships, food webs, etc.), 3) their ecological and physiological durability (are they easily damaged and fragile or do they tolerate perturbations [types need be specified] well?), and 4) their

ability to recover (including time and previous structure). All of these studies from baseline "alpha" ecology to predictive and functional aspects should commence at least three years prior to any development and continue throughout the entire project to monitor the environment. The leasing agency should be given full authority to prohibit or terminate any activities that prove detrimental to Vital communities within the OCS region.

As a final note in this regard, all estuaries and other areas designated by governmental agencies (State Water Quality Control Board, State Coastal Zone Commission, etc.) should receive special consideration and protection.

Respectfully submitted,

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Analysis of the Draft E.I.S. as It Relates to Marine Botany

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Analysis of Environmental Draft Statement
DES 74-90 U.S. Dept. of Interior

Prepared for City of Los Angeles
By David J. Chapman

My comments are addressed only to the discussions concerned with marine plants and phytoplankton. The environmental statement has been considered in its entirety, but special consideration has been given to those sections appropriate to Southern California.

STATEMENT ON OVERALL PROPOSAL

One of the most noticeable features is the heavy reliance upon governmental reports, meeting abstracts and survey-type publications for referenced data. These sources are in themselves condensations or synopses of data. This in turn means that this statement is in some respects a condensation of a condensation with all the problems that such an approach brings about. In that section concerned with the Environmental Impacts of the Proposed Action, there was little discussion or consideration of information gained world-wide about oil pollution effects. Admittedly this is concerned only with the U.S. but this other information is applicable. An Environmental Impact Statement should, represent a thorough documentation of the problem and its effects. I do not feel this particular E.I.S. meets this requirement.

produced per unit time; productivity bears some relationship to it. Blanket statements (page I-529) like "comparisons from different years are of little value" can be misinterpreted by the non-scientist. While they may be true, possible underlying factors such a s similarity of methodology must also be considered. It is possible if uniform and similar techniques are used that comparisons can have value.

In the section that is concerned with the description of the environment, it would have been far more appropriate to eliminate the distinction between offshore and near shore and coastal zone. Nowhere does there appear to be a precise delineation and in some instances no attempt appears to have been made to abide by the approximations. On I-331 there is a discussion of epiphytic diatoms. Presumably these are near shore diatoms (by virtue of being epiphytic) in which case one would expect the discussion under the section of Near Shore Environment. I would also comment that Cyanophyceae (bluegreen algae) are not really a significant part of the benthic flora. They sometimes are (as a bloom) a significant part of the phytoplankton (e.g. Trichodesmium).

These weaknesses in the E.I.S. result in a definite lowering of the statement's quality and merit. It raises questions in my mind about the scientific expertise and qualifications of the preparer(s) of the report. Or was it a non-scientist just abstracting from available government reports and books?

On Page I-431 the report states "Their (phytoplankton) importance cannot be overstated." This is indisputable and as a result I would have expected a more thorough, uniform and knowledgeable coverage of productivity comparisons, phytoplankton blooms, productivity fluctuations.

The E.I.S. has a serious omission which is inexcusable and I feel must be incorporated. The discussion on attached-benthic (intertidal and subtidal) algae is grossly inadequate. Overall coverage and description of the algal flora is poor (e.g. for the Alaska Pacific region). Most significantly however, there is no mention of Chondrus in the Northeast. This is the basis of a commercial industry. There is no mention (except a few sentences) of the kelp beds (Macrocystis) and the related industry in Southern California. Much time and governmental money has been extended on kelp bed research with a view to maintaining the viability of the industry. To ignore this, (and the possible future industrial use of other algae) is a serious omission that should be corrected. Where algae have been mentioned (e.g. I-713) it has been in an area of general insignificance. The algal flora inhabitating mangrove roots is environmentally less significant than kelp beds or intertidal-subtidal benthic algae.

SCIENTIFIC MERIT

The comments here will be concerned mainly with the sections on the Environmental Impact of the Proposed Action.

I agree with the statements (II-157 ff) that quantification of the environment is poor and this is an essential component of monitoring the environment. They state that their projections (II-159) are based on more recent work. These tend to be primarily qualitative and this should be emphasized since it makes predictions on the extent of potential damage difficult. In my opinion a very real need exists for a thorough quantification of the environment before any leasing or drilling is undertaken. This is an essential prerequisite for any environmental monitoring both on a short term (e.g. major blow out or spill) and long term (cumulative effects) basis. This lack of quantitative base line data is a mojor problem and the scant coverage given to this by this E.I.S. represents another major criticism.

I would take specific issue with the statement (II-158) -- "No geographic area would have ten million acres -- aside from catastrophic localised spills." Even if one accepts the thesis that the Gulf of Mexico has not been radically altered in 25 years by oil drilling activities it is not valid to use the Gulf of Mexico as an analogue for totally different regions such as Northeast coast, Alaska and Southern California. A comparison of producitivity values

Coastal Gulf Alaska	150 gms C/ m^2 / year
Southern California	200-400 gms C/ m^2 / year
Gulf of Mexico	54 gms C/ m^2 / year

and the floral comparisons indicate totally different environments and problems. I cannot accept, on this basis, their statement "---effects would be generally less than those observed in the Gulf of Mexico." Isn't it more a statement of hope?

I would agree that some accomodation and adaptation will occur over time, but the important thing is to what extent and in what way. Again, baseline quantification is needed. I do not question their statement about level of catch in Gulf of Mexico fisheries, but is this due really to an undamaged or adapted ecosystem or due simply to increased sophistication in technique and improved knowledge of fisheries. What fisherman catch over a 25-year period is not my idea of a sound basis of ecosystem quantification and stability (see later quoted comments by Oppenheimer).

In general I find that this whole latter part of the E.I.S. has more a tone of advocacy with a tendency to down play possible harmful effects. The statement should have amplified on the problems of toxicity of drilling mud constituents. Is there for example any possibility of some constituent triggering a phytoplankton bloom. I do not like the statement (II-160) "However, many toxicities are determined in laboratories and field conditions are distinctly different." I agree field and laboratory are different, but well-designed laboratory experiments can be very applicable to field work, especially if the problems of concentration, exposure in-

stability in sea water etc. are considered. Their comment should not be taken to imply that toxicity results cannot be applied to field conditions simply because they were performed in the laboratory.

Page II-161 mentions existing refinery capacity as being sufficient. Is this absolutely the case? I would have expected some discussion of the environmental impact of new refineries. Presumably they are a distinct possibility, and thus their environmental impact should be considered.

In the discussion on phytoplankton there is evidence to suggest that probably spilt oil itself has no permanent or totally lethal effect on phytoplankton. Temporary effects over a year or so in e.g. productivity efficiency may well occur. However, a problem that is significant and should receive more consideration is the effect of emulsifiers and detergents. Research has indicated that these are far more lethal and even in very low concentrations are deleterious to phytoplankton. In the event of a mojor spill would the company plan to use such compounds in cleanup operations?; would there be legal restraints against their use? This is a consideration that should be covered. The data presented and the problems of interpretation emphasize the lack of, and need for satisfactory baseline data for the environments.

The E.I.S. (II-164) states that no evidence exists for spilled oil entering the marine food chain, yet this is in

contrast to (e.g.) Blumer's statements referred to on Page 167. I would agree - in principal - with the comments that phytoplankton may not be seriously impaired by a major spill. Although they have mentioned it, this viewpoint should be strongly tempered by considerations of where the spill will occur, it's size, natural dispersion, mechanical dispersion (e.g. emulsifiers). It is true that the rapidity of phyto-plankton multiplication and the continual "movement" of the oceanic environment would probably bring about replacement of the population within a year or so. But what about the long term cumulative effect, and in this regard I would refer back to Blumer's comment on II-167 with regard to the comments of Oppenheimer, St.Amant and Jones (167 ff) I would just emphasize again that there must be a distinction between long term effects (about which we know little) and short term effects resulting from one shot catastrophic spills about which we do know something).

There is a tendency in this statement to relate "lack of evidence" to paucity of results. One must distinguish between lack of evidence caused by paucity of results and investigations and lack of evidence caused by paucity of results and investigations and lack of evidence caused by the failure of results and experiments to indicate. In an overall consideration it would appear that coastal lands (marshes, swamps) are far more fragile and susceptible than the phytoplankton. With regard to Southern California the wetlands are a lesser consideration than in the Gulf of Mexico and Southeastern United States.

The other tendency, which I again caution against is the use of results and observations from the Gulf of Mexico as to predict for other areas. The Gulf of Mexico is quite different from the other areas, such as Southern California.

OMISSIONS

This section refers to aspects that are missing from the statement and that I feel should have been incorporated.

The most obvious, and most serious, is the paucity of coverage given to the attached algae. This is particularly important when it is realised that this involves commercial industry in the Northeast and Southern California. This is a serious weakness of the E.I.S.

There is uneveness in coverage of the phytoplankton, particularly in the realm of productivity and phytoplankton blooms.

I also feel the overall quality and depth of the proposal would have been enhanced by reference to work outsidd the Americas, but which is appropriate to general pollution.

I would also have expected a "what if" consideration. There is no consideration of how O.C.S. oil spills might be handled. This is critical in assessing the possible effects, especially with regard to possible use of emulsifiers and detergents.

WHAT IS NEEDED

It is quite obvious that a thorough baseline quantification of the environment is needed, before any drilling

is undertaken. This is a sine qua non for monitoring the environment and possible changes. The E.I.S. in one section mentions a two year time span. I think three is minimal, in order to give time to cover two growth cycles and observe normal fluctuation.

There should be some consideration and estimation of the economic consequences of possible disruption of, for example, kelp beds, abalone fishery (by disruption of algal beds), disruption of marshland - wetland reclamation.

A concerted effort is needed to build up a basic body of knowledge about side effects of oil operations (e.g. effect of drilling muds) on phytoplankton. This is significant for areas of high productivity. This statement is made with particular reference to the implication that what has or has not happened in the Gulf of Mexico will be applicable to other areas.

<u>SUMMARY</u> (As applied to Algae and Phytoplankton)

Overall the statement is comprehensive with no major factual errors. There are some major and serious deficiencies. These have been referred to. The statement is however characterized by a lack of uniformity or eveness in depth and quality of coverage. An E.I.S. statement should be a critically prepared document, and this I feel is a weakness of this one. I wonder if this is not the result of the training and level of expertise of the preparer and

and the method of preparation.

Although one does not pass on the acceptability or otherwise of this E.I.S. I would if asked, rate this E.I.S. as marginally acceptable for reasons given above.

CHEMICAL OCEANOGRAPHY

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BLM DRAFT ENVIRONMENTAL STATEMENT

CRITIQUE ON SECTIONS DEALING WITH S. CALIFORNIA.

Evaluation of Accuracy Concerning Statements on Chemistry

The EIS appears to give a relatively accurate description of the environmental factors controlling air and water quality in the Southern California environment. The discussion is, however, very brief and selective. Only two pages are devoted to S. California, 1½ to central California and 4½ to the San Francisco Bay area. No attempt has been made to describe background levels of nutrient content or base metal concentrations in the coastal waters. There is virtually no reference to the distribution pattern of petroleum hydrocarbons in coastal waters. No attempt has been made to discuss the chemistry of the sediment which may affect the bottom-dwelling organisms.

Specific examples were chosen to indicate that adverse effects on the marine plant or animal communities can result from industrial and social activities presently operational along the coast. No attempt was made to discuss the operational hazards associated with offshore drilling in the Santa Barbara Channel.

On pages 260-267, an attempt was made to describe the hazards resulting from increased production, refining and accidental spill of petroleum. Values are given for average waste discharge contents of toxic gases, salts, hydrocarbons or soilds. No attempt was made to estimate the total mass of effluents which may be released during normal operations.

Because the document is very brief, its treatment of factors concerning quality of the environment are somewhat superficial. However, there does not appear to be any attempt to mislead or to misrepresent the facts.

State of Present Knowledge Concerning Chemistry of Water and Sediment on Southern California OCS

A great deal of work has been undertaken on the distribution of nutrients, salinity and oxygen in the waters along much of the shelf. The data has been collected by the Hancock Foundation, USC from 1950, and more recently by combined efforts of Scripps Institution of Oceanography and the National Marine Fisheries Service, Southwest Fisheries Center. Most of the studies have been made to depths of about 500 meters and the data obtained are mainly used for hydrographic interpretations of the characteristics of the water column. The data is also useful for interpretation of current movement and identification of water masses.

Some studies of a random nature have also been made on the trace metal content of coastal waters. In general, only waters within the channel islands along shipping routes, within harbors and at the outlets of sewage outfall pipes show significant deviation from normal deep-sea water characteristics.

Work has been undertaken on the distribution of heavy metals in the fine-grained sediment of the coastal shelf basins,

especially the near-shore basins, and along the entire coast. A detailed study on trace metals and total hydrocarbons has been conducted by USC on the sediment of the Los Angeles Harbor, and was expanded out to Santa Catalina Island. Probably the most comprehensive studies on chemical pollutants are being undertaken adjacent to the sewage outfalls extending from Ventura to San Diego counties under the direct participation of the Southern California Coastal Water Research Project.

Virtually no recent work has been undertaken on the distribution of petroleum hydrocarbons in either the water column, the sediment or the organisms. Some studies were performed about 15 years ago on hydrocarbon distribution in fine-grained sediment from a few basins. More recently, studies have been made by USC on seeps and sediment adjacent to the Santa Barbara Channel operations.

Our knowledge of the distribution and controls of pollutants on the OCS is very poorly understood at this time, through lack of data.

Baseline Information Which Needs To Be Gathered

From the foregoing discussion it is obvious that a great deal needs to be known about the chemical conditions of the OCS prior to monitoring for changes which may occur as a result of exploration and production.

First, it is necessary to obtain a good understanding of the natural distribution of hydrocarbons both in fine-

grained and coarse-grained surface sediment. This should be obtained for both oxidizing and reducing conditions, to determine whether exposure to oxygen causes recognizable changes.

Second, background studies on hydrocarbon distribution in the water column should be made at least on a grid of 100 square miles at 4 or 5 depths.

Third, two or three representatives of dominant genera of bottom-dwelling animals, fish and zooplankton should be analysed to determine the level and nature of their hydrocarbon contents.

Fourth, a detailed investigation should be undertaken to identify the natural oil and gas seeps on the S. California borderland and to determine their characteristics using a large variety of parameters. It may ultimately become necessary to resolve whether oil slicks have resulted from natural causes or from spills during production.

Fifth, certain trace elements, particularly radioactive elements related to the uranium series, such as lead-210 and radon, may be extremely useful in allowing for evaluation of sediment movement and rates of accumulation. They may also allow a determination of which sediments are stagnant and have no animal life in them and which are being reworked by burrowing organisms.

Sixth, an experimental program should be launched to determine the toxic effect of petroleum on local animals and plants. In particular, it would be important to determine

the organs which are most affected and the threshold concentration factors which are necessary to affect any toxicity.

Last, some studies need to be undertaken to determine the degradation pathways of petroleum. What fraction is evaporated and how long does it persist in the atmosphere? An important question is whether aged petroleum in seawater becomes more or less toxic to organisms. It would also be of value to estimate what proportion of the hydrocarbon is biologically degraded and what proportion is removed by atmospheric interaction. Such studies need to be done locally, as toxicity levels and biodegradability depend on the chemical nature of a particular petroleum.

Special Problems Associated With Petroleum Exploration on the OCS

(1) Operational pollution effects

During exploration and production, pollution will occur primarily through four sources.

(a) Drilling mud released from drilling platforms which will reduce optical transparency of the water and may form a dense layer overlying the natural sediment surface. In such a circumstance, anoxic conditions may be established in the sediment causing production of hydrogen sulfide and elimination of benthonic animals. This should only cause local disturbance.

(b) Crude petroleum released from drilling mud and other drilling procedures. The amounts here are probably very

low and would not constitute any appreciable hazard, especially in deep water far from shore.

(c) Waste gasoline and exhaust fumes may be expected from normal traffic of launches, tugs and other service vessels. Much of these waste products will be volatile and will only have a short duration in the sea.

(d) Heavy metals will be released from drilling rigs, formation water, crude oil and gasoline. Probably the most hazardous will be lead, which might be relatively soluble in saline water. Vanadium and nickel contents might also represent a hazard, which will have to be evaluated.

(2) Accidental spill

Probably the greatest danger to OCS operations will come from a single large spill. The reason for this, is that the petroleum could form an impermeable layer on the ocean surface preventing exchange of gases with the atmosphere and also absorbing visible light. It should be recognized, however, that for many reasons, the OCS of southern California is a relatively safe area in some respects, but potentially vulnerable to an oil spill in others.

First, the north-to-south-moving California current would tend to move the surface oil film away from the coast.

Second, because of topographic features of the shelf, areas overlying banks are subjected to relatively swift

bottom currents and substantial swells. Hence, water movement would accelerate dispersal and oxidation of the oil.

However, the topography also introduces a potential for damage in two environments. One is the coast along the channel islands which could be exposed to oil. Intertidal pools, nesting grounds, etc. could be endangered. Second, there are numerous basins within the shelf where water movement is very slow, and the oxygen content of water is greatly reduced. If petroleum does settle there, it may cause further removal of oxygen and create temporary stagnant conditions. THe biota in these basins is probably not as rich as on banks and platforms and damage would probably not be significant.

(3) Longevity of pollution effects

The longevity of an oil spill cannot be estimated theoretically. Becuase petroleum degradation is controlled by both biological and non-biological processes, it will depend on the following environmental conditions. Roughness of sea and wind velocity, temperature of sea surface, nutrient content of surface waters, particulate content of water column and chemical nature of the crude oil. Small spills may be dispersed in a matter of hours in the open sea.

Probably the greatest danger comes from oil being washed on beaches at high tide and smeared along an entire beach front. Oil slicks are frequently formed from sudden

releases of natural seeps between Ventura and Santa Barbara. One such slick which drew public attention in October, 1974 was virtually unnoticeable within two days and only left small tar residues on the beaches. The effects of the 1969 Santa Barbara catastrophy had essentially disappeared from the beaches one year after the accident.

(4) Effects of dispersing agents

Probably the most controversial aspect of combating oil spills is the effect of detergents or dispersing agents. The classical case most frequently quoted by opponents of using chemical agents, is that of the Torrey Canyon accident off Cornwall, England in 1967. It was found here that the biological effect of the detergents was more detremental than the effect of the oil. Proponents, however, believe this was due to use of polyaromatic-type substances in the dispersants. This lobby believes that use of aliphatic fatty acid or alcohol derivatives, which are biodegradable, offers a great advantage to increasing rate of oxidation of oil as well as acting as non-wetting agents. The opponents counter that dispersing petroleum increases its solubility in seawater, and hence increases its probability of entering the metabolic pathway of zooplankton and filtering organisms, hence causing it to be more hazardous. This question should be resolved quickly.

Summary of Hazard to Quality of Sea and Air by Oil in OCS Operation

It is without question that any industrial operation on

the OCS offers a potentially destructive hazard. Because of the nature of the S. California environment, the greatest danger might come from an accidental spill or blowout which could affect the biota along the coastal regions of the channel islands. Such accidents would probably have little effect on the environment along the mainland, unless an uncontrollable blowout would persist for several days or weeks.

During the baseline study to be undertaken by the BLM on the OCS, work on the channel island shoreline should not be neglected. Contingency plans should also be established for rapid oil removal, both from the seawater surface and from the coastline. It would seem that with the experience already gained, and the time still available for planning and investigation, risks emanating from petroleum production on the OCS can be kept within tolerable bounds.

SEISMIC PROBLEMS

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REGIONAL SEISMICITY
OF SOUTHERN CALIFORNIA AND ITS OFFSHORE
AS RELATED TO
DEVELOPMENT OF OIL AND GAS ON THE OUTER CONTINENTAL SHELF

I. Introduction

The coastal zone of southern California is part of a much larger seismic province, consisting of northwestern Mexico and most of California, dominated by the active San Andreas fault system. Most of the seismicity of this region is directly related to, and consistent with, the regional stress pattern responsible for this important fault. A detailed analysis of active faulting and the associated seismicity should be a primary concern for oil and gas development of the outer continental shelf.

A. For the purpose of the following discussion it is necessary to define the phrase "active fault". Two classes of active faults have been defined by Jennings (1973).

1. Those faults which have displaced Pleistocene or Recent geologic units (less than 2 m. y. old)

2. Those faults which have historically broken the surface along the fault trace, either during a seismic event or by creep. This type of fault logically must be considered potentially more hazardous.

A third type of active fault should also be recognized; that which exhibits microseismicity or an alignment of epicenters along the fault trace. Such epicentral alignments may be along faults which have not broken during historic time but which may have periodicities between destructive events on the order of hundreds of years and can thus be considered only slightly less hazardous than the Type 2 events of Jennings.

For the purpose of recognizing active faults in the offshore region, the following subdivisions of the Type 1 faults of Jennings may prove useful:

1. Active during the last 10,000 years as evidenced by offset of the most recent sediments

2. Active during the last 2 m. y. Either the most recent sediments are not offset or this evidence is lacking.

Thus the word active in this discussion will refer to both the Type 1 and Type 2 faults of Jennings, as well as those which exhibit seismicity.

B. In principle, two aspects of seismicity must be considered:

1. A possible causal relationship between resource exploitation (drilling, withdraw by repressuring, etc.) and induced or accelerated seismic activity, and,

2. Hazards to structures, the environment and human welfare resulting from resource exploitation in a naturally seismic region.

The following discussion addresses these points, evaluates the existing draft environmental impact report and finally suggests additional studies needed.

II. Possible Seismic Hazard Resulting from Resource Exploitation

Causal relationships between oil field operations and seismicity are poorly understood. An analysis of the problem can be made by examining the historic record in California and reviewing the relatively few case studies.

A. There are two methods by which oil field operations could conceivably cause seismic events:

1. By inducing local stresses in the subsurface which are in turn relieved along local fractures. These events should not be too energetic since the energy budget as determined by the field activities is relatively small.

2. By causing existing local or regional stresses to be relieved along local faults.

Most of the major oil fields in southern California are associated with major faults, many recognized as active. During the fifty years of oil field operations in southern California no potentially destructive earthquake has been known to result from these operations. However, ground subsidence, sometimes along fault strands, and resultant minor earth tremors (Kovach, 1974) are known to result from fluid withdrawal. Thus it appears that method (1) above has been realized, but not method (2).

Studies by Teng, etal. (1972) also suggest that oil field operations in southern California have a negligible effect on seismicity. Healy, etal (1972) have shown that fluid repressuri of the subsurface can induce small earthquakes along pre-existing fracture zones in a hard rock medium under existing tectonic stress. The effect is attributed to the frictional decoupling across the fractures by increased fluid pore pressure. This method seems to be the most

likely mechanism for relieving existing tectonic stress. It is important to realize, however, that in a dynamic stress regime such as exists in southern California, these stresses would ultimately be released. Man's influence could only speed up the processes (perhaps beneficially by not permitting stresses to reach hazardous levels) or shift the zone of actual faulting.

Finally, most of the oil field operations are taking place in the "soft" sediments above the basement. The sediments may be largely decoupled from the stressed basement below and hence may be largely stress free.

In short, the likelihood of oil field operations causing an adverse seismic effect in the southern California area must be considered small.

III. Evaluation of Seismic Hazards Pertinent to Platform Construction and Development on the Outer Continental Shelf.

The principal seismic concern to outer continental shelf development is the hazard to structures, pipelines, etc., and the indirect hazard to the marine environment and coastal regions, resulting from severe ground shaking or ground breakage from a major natural-occurring earthquake. A secondary concern involves the carrying out of certain types of oil field operations (such as repressuring) in the presence of faults; in this regard fault zones must be considered as potential conduits from subsurface to surface.

A. Proximity to faults

The proximity of structures to active faults is of fundamental concern. Platforms should not sit astride, or drill holes should not intersect active faults. Pipe lines crossing active fault traces must be suitably designed. Repressuring operations and tapping of high pressure subsurface horizons should be considered vis-a-vis proximity to faults--active or inactive. The degree of shaking (acceleration) is strongly related to distance from epicenter

B. Recurrence intervals

Recurrence intervals for maximum likely earthquakes on influential faults can be determined from the coastal zone and borderland seismicity. An example of a recurrence relation is shown in Figure 2 as determined from the seismicity of the region containing the west L.A. basin, Santa Monica and San Pedro basins. Facilities should be designed for the maximum event with a reasonable probability during facility lifetime. For example, from Figure 1, a magnitude 6 to 7 event should be considered as reasonably certain over the next 100 years for the region given above. Recurrence

relations can be derived for specific regions (Figure 2) or individual faults. A magnitude 8.0 to 8.5 event is considered reasonably certain for the southern San Andreas fault in the next 50 to 100 years. Such a large event, although centered perhaps 50 km inland will have significant effects offshore of southern California.

In short, recurrence intervals for potentially destructive earthquakes affecting a particular location on the outer continental shelf may be anywhere from 50 to several hundred years.

C. Acceleration factors

Acceleration factors should be evaluated for all of the important events considered under (B) above. There are two methods by which accelerations can be assessed.

1. Maximum acceleration attained during the course of shaking irrespective of frequency content. This method is often useful for small structures such as houses since the dominant frequency of shaking is often equivalent to the structures response. However, as an example, for platforms, although peak acceleration can still provide useful information, it may not predict the specific response. Peak accelerations for "hard rock" sites (Figure 2) have been determined for different sized earthquakes as a function of distance by Schnabel and Seed (1973). It is important to note that for specific sites, peak accelerations could attain 1 g in the O.C.S.

2. The determination from accelerograph data of the Response on Fourier spectrum for a given earthquake. This method considers ground motions in terms of frequency content of the incoming seismic signal. Determination of Fourier or Response spectra are necessary to predict the behavior of large or complex structures. Spectra such as these are also available for typical earthquakes, although they are much more likely to be dependent on local geologic conditions.

D. Substrate character

The offshore region of southern California consists of a series of basins and ridges. The basins contain thick sections of unconsolidated muds and silts presumably overlying Tertiary sediments. The ridges are often devoid of unconsolidated materials, although

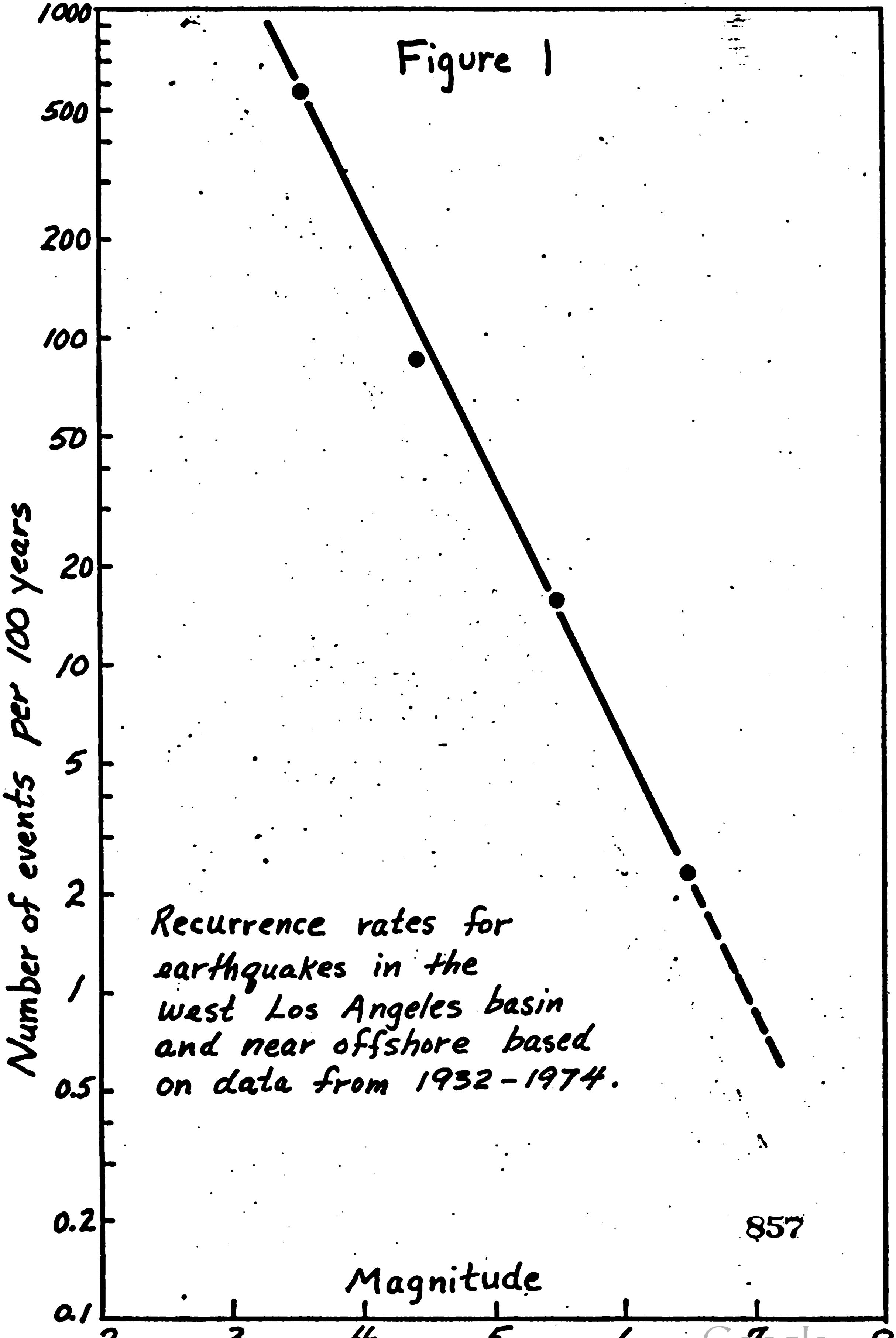
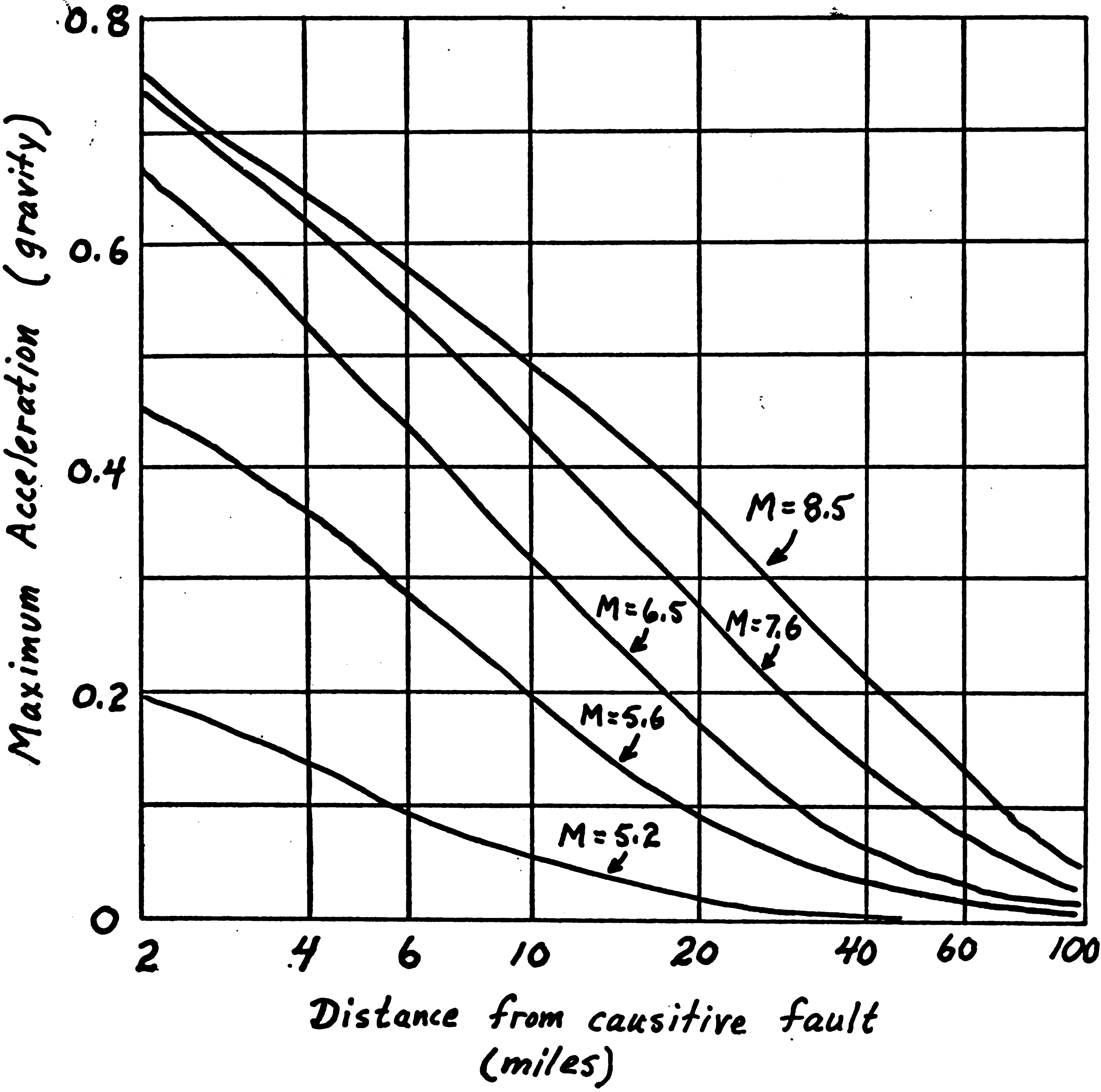


Figure 1

Recurrence rates for earthquakes in the west Los Angeles basin and near offshore based on data from 1932-1974.

857

Figure 2



Maximum Accelerations in Rock
for various magnitudes

locally they may be present with thicknesses ranging from a foot to several tens of feet. The ridges are largely composed of thick sequences of upfaulted and folded mid to late Tertiary sediments and associated volcanic rocks. The nature of and depth to crystalline basement is generally not well known for most of the offshore area.

The seismic response (shaking) of a given site will depend critically on the physical nature of the substrate. The nature and thickness of unconsolidated sediments are of principal concern. In addition to thicknesses of substrate components, the following engineering and geologic characteristics for assessing substrate stability should be determined: density, porosity, shear strength, compaction potential, solifluction potential, mineralogical composition, and grain size.

E. Landslide Potential

The potential for seismically induced landsliding exists in specific offshore regions. Types of landslides and related occurrences include:

1. Slumping and settling which are of principal concern in areas of significant topographic relief (such as near escarpments) or with specific substrate type (such as compactable materials).

2. Turbidity currents which are of concern at the head of, within, and at the mouth of submarine canyons. Sites where rapid or catastropic bottom sediment flow is observed to occur should be avoided.

3. Terrestrially derived landslide debris which is only important for sites adjacent to an unstable coastline, such as near well developed palisades.

IV. Major Faults Pertinent to Proposed O.C.S. Lease Lands

The active faults are moderately well known for the inner borderland (San Pedro, Santa Monica, and Santa Barbara shelves) but poorly known for the outer borderland (Ziony, et al. 1974). The following inner borderland fault zones are considered potentially hazardous (note: most of these fault zones consist of several strands):

A. For San Pedro Shelf

1. Newport-Inglewood Fault Zone

2. Palos Verdes Fault Zone

B. For Santa Monica Shelf

1. Palos Verdes Fault Zone

2. Santa Monica-Malibu Coast Fault Zone

C. For Santa Barbara Shelf and Northern Santa Rosa-Cortes Ridge

1. Santa Rosa Fault

2. Santa Cruz Fault

3. Santa Ynez Fault

4. Arroyo Parid Fault

5. A group of E W trending unnamed faults in Santa Barbara channel (Jennings, 1974)

Many faults have been postulated by Moore (1969) for the outer borderland, but their activity has not been documented. Moore suggests that most of the escarpments in the outer borderland are fault controlled.

The San Clemente escarpment--Aqua Blanca Fault trend is recognized as the most important seismically active zone in the outer borderland.

Noteworthy is the fact that faults south of the channel islands are NW-SE trending and probably involve right-lateral strike-slip and/or normal components of displacement while faults within the Channel islands and to the north involve left-lateral strike-slip and/or reverse components of displacement. Unpublished data on active faults in the offshore regions are available from the U.S.G.S. and U.S.C.

V. <u>Seismicity of the Borderland</u>

The general level of seismicity in the inner borderland does not appear to be appreciably different from the near-coastal onshore regions (U.S.G.S., Caltech, U.S.C. seismic station data). Damaging earthquakes have occurred offshore near the coast; these include the 1925 Santa Barbara and the 1933 Long Beach earthquakes. The seismicity, however, does appear to diminish with distance from the coast. This trend is poorly defined due to paucity of data.

Finally, the hypocentral depths for earthquakes in the borderland are not well established due to a combination of poor station control and lack of detailed subsurface seismic velocities. This information is useful in assessing the relationship between subsurface stresses and ground movements resulting from fluid injection-withdrawal. Hypocentral depths in the borderland probably occur between 5 and 15 km.

VI. Earthquake Risk

The risk to a particular structure due to a given earthquake is a function of that structures engineering design vis-a-vis its proximity to the earthquake epicenter. Thus risk can be mitigated by appropriate siting (within the limits of development objective) as well as by appropriate structural design. Substrate failure involves more difficult (if not impossible) engineering design than ground shaking. Suitable structure can probably be designed to withstand the strongest expected ground accelerations ($\sim$1 g).

VII. Critique of Draft Environmental Statement Discussion on Earthquake Hazard.

The portion of the E.I.S. pertinent to seismic hazard is contained in Section 3 (Pacific Region); subsection (a.) (Geology); subsection (1)(Southern California and Santa Barbara O.C.S.)--pages 356-382. In short, an adequate discussion of earthquake hazard on the O.C.S. is lacking. Specific comments are as follows:

A. P. 356 - It should be noted that basins and ridges are probably both fault and fold controlled. It might be worth evaluating hypotheses of borderland development - different styles of tectonism are suggested by several authors (Yeats, et.al. 1974; Howell, et.al. 1974, etc.)

2. P. 365 - The important near shore faults (Palos Verdes, Santa Monica, Malibu, Newport-Inglewood) have been neglected as has the apparent decrease in seismicity from inner to outer borderland.

C. P. 370 - The word "active" should be defined

D. P. 370 - The sentences beginning "The present state-of-the-art . . . " should read:

The present state-of-the-art is such that most active faults can be identified and accurately located through detailed geologic mapping, seismic reflection profiling, seismic monitoring, trenching and drilling. Although this work may be expensive, it is necessary to guide development so that losses due to fault displacement on active faults can be virtually eliminated.

E. P. 370 - Effects of ground shaking have been neglected.

F. Fig. 54 (and p. 370 "Earthquakes") is a bit misleading and probably should be omitted. It is probably not accurate especially for O.C.S. - certainly not accurate on a small scale. This is a poor way to depict earthquake risk. A regional seismicity map would be one step better.

G. A figure showing "active" faults has been omitted.

VIII. Suggestions for Proposed Studies

A. High resolution (3.5 kHz) and high energy (spa ker, air gun) reflection profiling should be carried out at 1 km grid spacing on lease lands and along nearby suggested fault trends to determine geologic "activity". This work should be integrated with existing data from commercial sources, U.S.G.S., U.S.C., etc.

B. Seismicity of Borderland

The number of land based stations cannot be made sufficient to examine detailed seismicity. Ocean Bottom Seismometers (OBS) are needed for control on both epicenters and hypocenters, as well as fault mechanism. A minimum of 6 OBS should be used to monitor lease regions for a minimum period of 3 to 6 months per region. Stations should be established on all islands (in some cases more than one per island).

C. Ocean Bottom accelerometers should be immediately placed at prospective (or typical) platform sites.

D. Vibracore or rotary drill samples of substrate at prospective (or typical) platform sites should be taken as soon as possible for substrate properties analyses. This work should be supplemented with detailed 3.5 kHz high resolution seismic profiling.

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The removal of large volumes of fluid in California reservoirs has led to differential subsidence, earthquakes and fault movement in many California oil fields (Yerkes and Castle, 1969). The most notable example of subsidence triggered earth movements occurred in the Wilmington oil field in 1947, 1949, 1951, 1955, and 1961 (Kovach, 1974).

Earthquakes have also damaged producing wells in the Rosecrans oil field (Martner, 1948) and the Dominguez oil field (Bravinder, 1942). The Arvin-Tehachapi shock of 1952 produced broken pipelines and a number of casing failures (Johnston, 1955). Since a small amount of fault displacement can cause a casing break or a broken pipeline the future possibility of similar occurrences offshore cannot be completely dismissed. One cannot also overlook the possibility that if high subsurface pressures were released to the surrounding rocks in near ocean bottom reservoirs through fault movements or slippage and fractures formed to the sea floor an oil leak could develop.

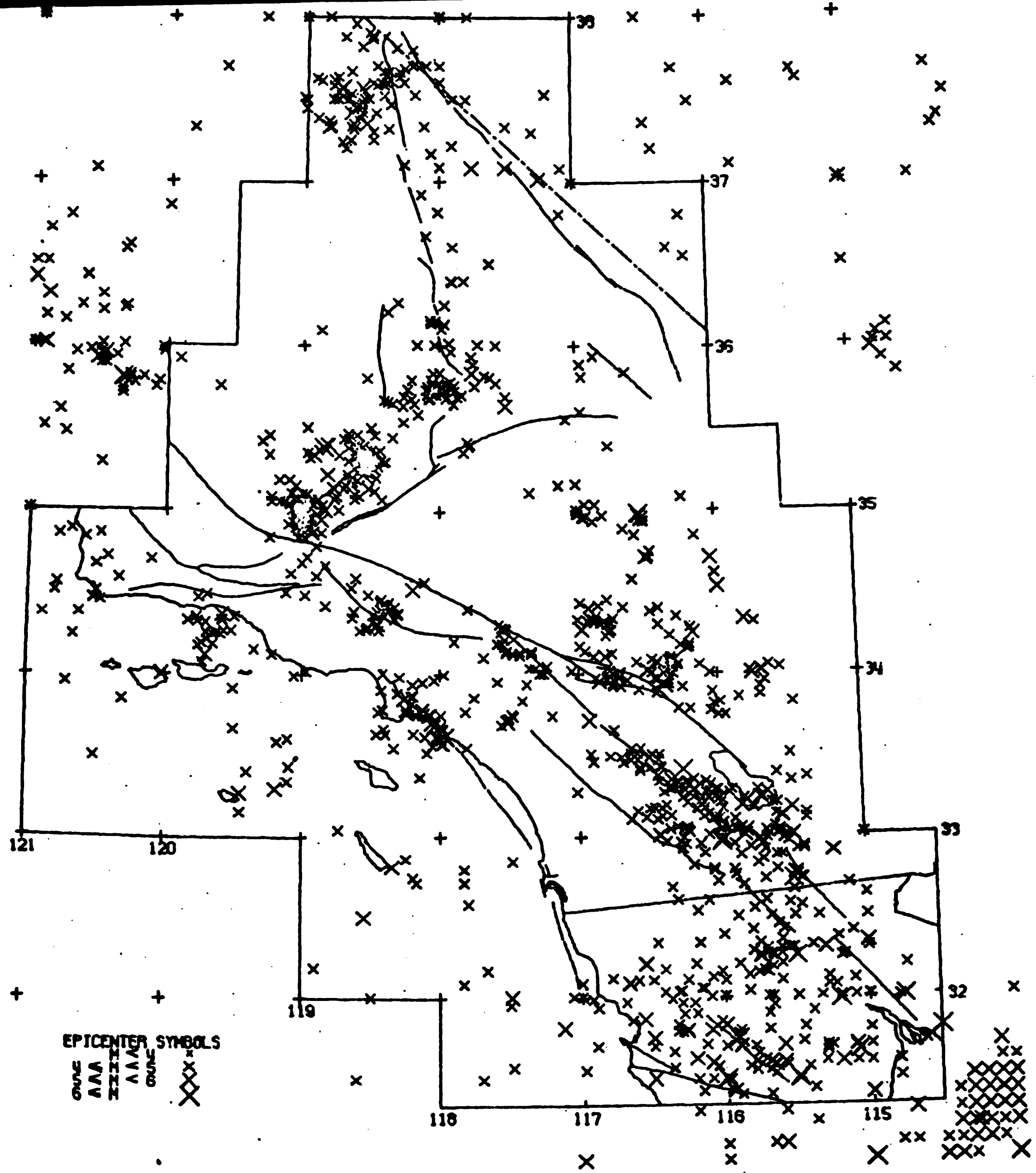
SEISMICITY AND ACTIVE FAULTS OF THE CONTINENTAL SHELF

California lies in the circum-Pacific belt where 90% of the world's earthquakes occur. In the framework of plate tectonics coastal California is located at the eastern edge of the Pacific plate which is moving northwestward against the American plate at a rate of several inches per year. Plate tectonic theory suggests that seismicity gaps, i.e. those parts of plate boundaries that have not experienced large earthquakes during the past tens to hundreds of years are likely sites of future major earthquakes or rapid seismic creep. There will certainly be destructive earthquakes in the California region in the future, emphasizing the need for prudent examination of earthquake hazards and risks.

is dominated by "basin and trough" topograhy and northwest trending fault scarps of high relief (Emery, 1960; Allen, et al. 1965). The location of earthquakes of magnitude greater than or equal to 4 which occurred in the offshore area of southern California during the time interval from 1932 - 1972 is shown in Figure 1. No obvious trends are conspicuous in the distribution of earthquake epicenters. Although the offshore region is not known to have been the site of a great earthquake (magnitude > 8) the historical record and the more recent instrumentally located epicenters show that earthquakes of at least magnitude 6 can be expected.

The existing distribution of seismograph stations in southern California does not allow precise epicenter locations offshore because of the azimuthal bias of land stations in California and the inadequate knowledge of crustal structure in the offshore region. Individual epicenters offshore are typically known to within only 15 km or so (a few larger events are located to within 5 km). Therefore, at present specific active faults in the offshore region cannot be recognized from the pattern and distribution of seismicity. It would be most useful and informative to accurately pinpoint active seismic zones in the offshore region. This could certainly be accomplished with several ocean-bottom seismometer installations, together with improvements in our knowledge of crustal structure.

Any ocean bottom pipeline offshore from California can be expected to cross faults and it would be important to map their locations by sub-bottom seismic profiling. Many faults in the region also have a topographic expression and the fact that fault scarps are preserved in



1932 THROUGH 1972, EVENTS EQUAL OR GREATER THAN MAGNITUDE-4

Figure 1. Map showing location of earthquake epicenters in southern California and offshore region (taken from Hileman, Allen and Nordquist. 1973).

relatively soft bottom sediments argues that relatively recent movement has occurred and can be expected to occur in the future.

GROUND MOTION AND FAILURE

Earthquake effects are related to magnitude - a measure of the energy released, and intensity - a measure of the severity of an earthquake at a particular location. Intensity in turn depends on the distance to the earthquake epicenter and local amplification effects produced by the thickness and physical properties of materials a few hundred feet beneath the site in question. The greatest amplitudes and the longest duration of motion are observed in thick water saturated unconsolidated materials. For example, studies have been made in the San Francisco bay muds (Borcherdt, 1969) which show that horizontal peak ground motion velocities are recorded with amplitudes 10 times greater than that observed on nearby bedrock areas.

Two areas of potential concern in offshore drilling operations are the rupture of pipelines carrying oil from the drilling platforms and damage of a drilling platform due to an earthquake. Because the presence of soft ocean bottom sediments could produce amplified shaking and possible liquefaction along any proposed underwater pipeline the distribution and thickness of unconsolidated sediments should be mapped and frequent core samples of these sediments taken to evaluate their response to seismic shaking.

An offshore drilling platform can be designed to meet a specified design load factor. For example, the drilling platforms in the Dos Cuadras offshore field in the Santa Barbara channel are designed for a seismic load factor of 0.15 times the acceleration of gravity g. However, it is fair to point out that the 1971 San Fernando shock of magnitude

6.6, only a moderate shock by seismological standards, produced the largest acceleration (0.5-1.5 g) ever recorded during an earthquake. Furthermore, Boore and Page (1972) have demonstrated that ground accelerations recorded within 10-15 km of faulting during moderate sized earthquakes have been significantly underestimated by some of the acceleration-distance relations commonly used in seismic engineering. Because strong shaking over a limited area can be extremely destructive, and because there is a lack of close-in ground acceleration data, the empirical relations in use for seismic design engineering may be inadequate to evaluate whether proper design considerations will be utilized for offshore platforms and pipelines. Some offshore platforms may have a resonant period of several seconds and long period ground motion effects have not been as carefully studied as shorter period motions.

One other mode of possible failure to ocean bottom pipelines needs to be mentioned - the possibility of damage from turbidity currents. Because we are dealing with a topographic region of basins 1/2 to 2 km deep separated by islands and banks, steep slopes can occur and turbidity currents could be generated that could possibly produce damage on ocean bottom installations.

TSUNAMIS

Tsunamis are unusually high sea waves triggered by earthquakes on or near the ocean floor or by large submarine landslides. They can be triggered by distant large magnitude earthquakes or locally by near earthquakes. Distant earthquakes have triggered tsunamis which have struckthe California coastline (Tsunami hazards in California, map, California Div. of Mines and Geology, 1972).

Tsunamis have also been generated along the western coast of the

United States due to earthquakes in the Santa Barbara channel (Hamilton et al., 1969). In 1812 an earthquake near Santa Barbara purportedly triggered a tsunami with reported wave heights of 50 feet at Gaviota, 35 feet at Santa Barbara and 15 feet at Ventura (Wood and Heck, 1966, p. 18). The magnitude 7.5 shock of 1927 off Point Arguello produced waves over 6 feet high. The possibility of tsunami damage to offshore platforms cannot be completely discounted. The critical factors to be considered are the height and velocity of the resultant sea waves and the particular stage of development of drilling or development of the offshore well at the time a tsunami strikes.

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MANPOWER AND MATERIAL SHORTAGES

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MANPOWER REQUIREMENTS FOR OFFSHORE OPERATIONS

GENERAL

The rate at which offshore leases can be developed is dependent on many factors -- not the least of which are the availabilities of equipment, tubular goods, capital and qualified manpower. The objective of the proposed changes in the rate of leasing OCS acreage is to increase the rate of production of domestic oil and gas. A prudent policy would be to select those options in the use of these limited resources which maximize the rate of oil and gas production and minimize the time delay in obtaining increased producing capacity. Of these factors, availability of technically trained personnel is a particularly important consideration.

In recent years U.S. offshore operations have been limited to the Gulf Coast area. Engineers have been hired and trained for those domestic operations consistent with the existing requirements. It would have been unreasonable to have anticipated the developing of any substantial reserve pool of trained personnel for whom no need currently existed and conceivably would not develop in the near future without changes in state and national policy for offshore leasing. However, most of the oil companies which would participate in an accelerated offshore development program have been active, not only in the Gulf Coast area, but abroad where restrictions on offshore operations have been less severe than in the U.S. Engineers with experience in the Gulf Coast area and overseas can be transferred for operations elsewhere

when leases become available. A limited number of engineers with previous offshore experience are available in California. Many of the skills required offshore do not differ appreciably from those required in conventional onshore operations.

If the U.S. plans to supplant a significant portion of the imported oil with domestic oil produced offshore, a timely decision must be made with respect to offshore leasing to permit the universities and industry to recruit and train personnel so that they will be available as required for the expanded offshore activity.

Particular attention must be given to finding qualified scientists and engineers to staff the agencies responsible for administering and monitoring offshore operations. Policies must be established within these agencies for training those currently employed and for recruiting high caliber personnel. The recommendations for meeting these requirements should be included in the EIS.

FACTORS AFFECTING MANPOWER AVAILABILITY

Effect of Leasing Policy

The requirements for technical manpower do not depend only on the rate of leasing but also on the policies with respect to the specific acreage proposed for leasing. On the one extreme, if the proposed acreage is primarily frontier acreage, the technical skills required initially will be strongly oriented towards exploration personnel such as geologists and geophysicists. Drilling will be from floating vessels with exploratory objectives. The requirements for drilling and production engineers will not be established until the success of the exploration program has been determined. On the other hand, if the additional acreage is primarily drainage acreage, the initial requirement will be for engineers to design and construct offshore platforms and production facilities. Later drilling, production and reservoir engineers will be required. The numbers of engineers required for these operations could be estimated reasonably well. Currently, the latter operations would be more limited by equipment than personnel availability. Recent changes in the economy, however, may result in steel goods being more accessible.

To minimize the environmental impact on coastal zones, the suggestion has been made that preference should be given to leasing tracts farther offshore over those near shore. This has been suggested, in particular, with respect to leasing off the California coast. Whether near shore or far offshore operations are preferred, the engineering skills for operating in deep waters and at long distances

from shore will differ in many respects from those close to shore. In California many of the areas near the coast have already been explored in considerable detail and plans for developing the fields are well advanced, including the formation of nucleus engineering groups to operate the fields if operations should proceed. On the Atlantic coast all offshore areas are considered frontier areas.

Rate of Developing Leased Acreage

The Environmental Impact Statement discusses insufficiently the basis for selecting 10 million acres as the amount of acreage to be leased in 1975 except to note the additional daily production to be anticipated from the lease sale in various areas. These additions to our producing capacity would certainly be highly desirable. The predictions show a non-linear relation between acreage leased and increased production, higher increments in leased acreage resulting in smaller increments of production. This is presumably because the better acreage would be leased first. No consideration is given in these estimates of other limitations on industry in effectively developing larger acreage allotments. In an appendix a summary is given of answers from respondents who were asked to estimate the time from leasing to first production and to peak production from various areas. These estimates do list factors which would affect the rate of developing leased acreage. Items most often mentioned are rigs, tubular goods, platforms and (less frequently) personnel. The effect of the total acreage leased appears not to have been considered, however. The critical question remains, then, how rapidly can industry find the equipment, capital and manpower to develop the offered acreage?

Congress, in authorizing funds for the EIS, specified that before leases are made the industry must establish that it has the equipment and other requirements to proceed with development of the leases at a satisfactory rate. A satisfactory rate of development has not been defined. The Western Oil and Gas Association has indicated in its study of offshore leasing for California that leases awarded in 1975 would not be productive until 1979. Production is estimated at only 67,000 barrels per day in 1980 and rising to between 700,000 to 1,000,000 barrels per day in 1990. These estimates are based on leasing 1.6 million acres. The estimates in the EIS for a similar area are three years to first production and eight years to peak production. This schedule of development would not appear to place any severe demands on the availability of manpower. The WOGA estimate is based on a one-time lease sale as proposed by BLM in July, 1974.

In this connection, it should be noted that the EIS does not propose a rate of leasing of 10 million acres per year. It proposes only that 10 million acres be leased in 1975. The Presidential directive states that in later years the amount of acreage to be leased will be based on market needs and on industry's performance record in exploring and developing leases. With these limitations, lack of diligence in the developing of leases for whatever reasons -- manpower or other -- would appear to be cause for limiting acreage offered for lease in subsequent years. Nevertheless, a more comprehensive study is required to determine what factors, other than acreage offered for lease, limit the development of increased offshore production. In recent years, however, the limiting factor has indeed been the rate of offshore leasing.

Competing Demands for Qualified Personnel

As noted earlier, a number of engineers, qualified for offshore operations, are currently assigned overseas. These people could form a nucleus for developing engineering staffs to supervise domestic offshore operations. To what extent this is possible is not known. Companies operating offshore in their foreign operations have made commitments which they must honor. They cannot indiscriminately remove engineers for use in U.S. offshore operations. In some areas such as Indonesia, technology is not well-developed and these countries rely heavily on U.S. trained personnel. In the absence of adequate supplies of domestic oil, we have relied heavily on them for crude imports as to Japan and other countries. In areas such as the North Sea, the leasing countries have made substantial progress in training their own engineers. Engineers with valuable experience may be available from these operations.

Within the U.S., secondary and tertiary oil recovery operations compete for certain classifications of engineers which are required for offshore operations. In general, tertiary recovery operations are more labor intensive per barrel of additional oil recovered than are operations in new reservoirs. Therefore, if one were faced with a choice in assigning personnel, maximum return in increased daily rate of oil production would be obtained in assigning engineers to offshore operations rather than secondary or tertiary recovery projects.

To some extent the same choices arise for other alternative fossil fuel sources. In general, developing new oil reservoirs gives maximum return in oil production capacity per unit of engineering time.

Similar considerations apply to onshore versus offshore exploration. Since the largest unexplored sedimentary deposits are offshore, chances of success are greater there than onshore. Most effective use of exploration talent would be in offshore operations if the objective is to maximize oil and gas discoveries with a given amount of scientific talent.

If shortages of technically trained manpower become critical in developing domestic fuel sources, consideration becomes essential of those alternatives which make most effective use of the talent available. Although the rate at which students are entering the engineering profession shows promise of increasing, significant shortages currently exist in the supply of petroleum engineers and may develop in other energy related fields. In any case, effective use of scientific and engineering manpower should be considered in developing a national energy policy. It should most certainly be considered in the alternatives discussed in environmental impact statements relating to energy.

Manpower Needs for Regulatory Agencies

An accelerated leasing program will make new demands for technically trained personnel for the regulatory agencies of both the federal and state governments. It will present substantial challenges to the USGS, BLM and other federal government agencies charged with the responsibility for administering the program and monitoring the offshore operations. Engineering and scientific talent will be required in federal agencies to provide resource assessment, supervise lease sales, monitor exploration and development activities and inspect

production operations. For these activities a wide range of technical talent will be required, including most scientific and engineering disciplines.

Of particular importance is the greatly increased geographic area to be included in the expanded lease sale. Offices for the BLM have been established in the areas for which leases are contemplated. The USGS is in the position of anticipating supervisory responsibility if the leasing program is approved but is only partially staffed for the increased work load.

The EIS does not make it clear what additional staffing has already occurred in these agencies or what additions to the staff are contemplated. The public must rely on these agencies to protect its interest. A high level of public confidence that they are carrying out their responsibilities effectively would insure more support for the offshore leasing program. For that reason the agencies must attract first class scientists, engineers and other personnel to accomplish this objective. To do so, they must compete with industry. The positions should be financially attractive enough to do so effectively. In addition training programs should be instituted to keep present personnel current on developments in engineering and technology. The efforts presently underway to accomplish these objectives, if any, should be discussed in the EIS.

Personnel for Emergency Operations

Qualified emergency personnel must be available to prevent spills or, failing that, to contain the spills with minimum damage. Standard procedures have been developed for the more common emergencies.

The skills required for these procedures are specialized but can be taught in a short time if qualified personnel and equipment are available.

The Industry has instituted short courses for drillers to train them in emergency measures for controlling well fluids. This course is currently being offered in LSU and will shortly be given at the University of Oklahoma. A similar course is being considered for California.

Special cleanup vessels designed to recover oil spilled on the surface are operational in California and the Gulf Coast. Any extension of offshore operations will require developing similar capabilities in those new areas. The number of persons required for these operations is not large, but it is essential that this equipment be available wherever oil spills could occur. This would include tanker operations in and out of harbors. Availability of this equipment should not impose a restriction on increased leasing of acreage in 1975.

SUMMARY

1. This Environmental Impact Statement is with regard to a proposal to increase leased acreage to 10 million acres in 1975. The proposal is not for an annual leasing rate of 10 million acres per year. Personnel limitations would not place serious restrictions on the development of the acreage proposed for offering in 1975, but experienced engineers would likely have to be transferred from the Gulf Coast and overseas.
2. For many reasons, including limitations in manpower availability, the industry probably could not sustain an annual rate of leasing of 10 million acres per year and still develop the acreage at a satisfactory rate. This depends, however, on the success in discovering new oil and gas reserves. It should be noted, also, that the proposal does not state what a satisfactory rate of development would be.
3. Types of technical manpower required and the times at which the various skills would be needed depend on the mix of acreage placed for lease.
4. The most critical manpower requirements are likely to occur in the abrupt increases in the staffs required for BLM, USGS and other federal government agencies. Every effort should be made to attract highly qualified personnel to these agencies.
5. In competition with other domestic fossil fuel sources, offshore oil fields promise to provide the largest increment in oil and gas production for the least number of technical personnel.

6. Emergency personnel are available in some areas now. Training additional personnel for this purpose does not appear to be a limiting factor in the accelerated leasing proposal.

A Critique of the Lack of Consideration of Enhanced Recovery Within the Draft Environmental Statement for the Proposed Increase in Acreage to be Offerred for Oil and Gas Leasing on the Outer Continental Shelf

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The Federal Government has proposed that through accelerated leasing an extensive program be mounted to quickly drill and produce new oil from unexploited OCS regions. It has long been known that vast quantities of oil are unrecovered from reservoirs even after primary and the most common secondary recovery operations are complete.

The current importance of this potential alternative source is recognized by articles such as "Improved Oil Recovery Could Help Ease Energy Shortage" by Ted M. Geffen (World Oil, page 84, October 1973), and the fact that the Federal Energy Administration hosted a December 1974 symposium in Washington, D.C. to examine possibilities for enhancement of recovery. Another measure is current titles in the petroleum engineering literature. The December 1974 Journal of Petroleum Technology contains an unusually rich lode: "The Use of Numerical Simulation to Design a Carbon Dioxide Miscible Displacement Project," "Alkaline Waterflooding for Wettability Alteration -- Evaluationg a Potential Field Application," "A Caustic Waterflooding Process for Heavy Oils," "Field Trial of Caustic Flooding Process," Oil Recovery by Alkaline Waterflooding," "Mechansims of Oil Displacement by Carbon Dioxide," and "The Sloss COFCAW Project -- Further Evaluation of Performance During and After Air Injection." The fact that this is an "Ancient" area -- long known but always targetted for consideration at some future date -- is shown by the long established literature. (Examples are Fayers and Perrine, "Mathematical Description of Detergent Flooding in Oil Reservoirs, AIME Transactions 216, p. 277, 1959, and Perrine, "Stability Theory and Its Use to Optimize Solvent Recovery of Oil," Society of Petroleum Engineers Journal, p. 9, March 1961.)

Thus a reasonable alternative to the proposed accelerated leasing program would be a less-accelerated offshore program combined with a substantially greater effort toward enhanced recovery from known reservoirs. By some criteria there might appear to be no advantage to this approach, but by others there are several possible important advantages.

As noted by Geffen, there are up to 50 to 60 billion barrels of already discovered oil as the potential resource. It is recoverable over the same time frame as in current OCS proposals. For much of this resource, each year of delay in attempts at recovery will mean abandonment of wells and other investments already made. Costs then are increased to such an extent that some oil becomes irretrievable. With enhanced recovery, no new environmental concerns are involved.

Cost-benefit evaluation from the internal cost standpoint of an oil company likely will place such methods at a disadvantage compared with new OCS oil. New oil comes at an acceptably low initial cost to the company. It increases the store of goods to dispense to the public at a profit over future years. There is no such benefit in dispensing with a private resource now which could be held for the future at perhaps negligible cost, and sold at the then current higher price.

But from the public viewpoint a different evaluation might follow. This alternative viewpoint would appear more appropriate in an Environmental Statement concerning a public resource. The fact that total loss of a part of the resource might be avoided would become an essential factor. A significant part of the alternative oil recovery effort could use different labor and technology, possibly creating a larger number of new jobs and with fewer possible bottlenecks.

In summary, the natural pace at which the petroleum industry seeks to utilize enhanced recovery is likely to be less rapid than would be desirable from a public policy viewpoint. Private commitments to such activities may be made only after all financial risk has disappeared. By way of contrast, it is characteristic of more entrepreneurial operations such as exploitation of new OCS regions that the difficulties tend to be underestimated. Some of the relatively untried methods for drilling and production operations proposed for Southern California in the Western Oil and Gas Association "Environmental Assessment Study" (October 1974) illustrate this optimistic point of view.

Federal environmental impact studies should provide an unbiased evaluation of each alternative. This certainly would appear to include careful re-evaluation of significantly increased use of enhanced recovery.

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ATTACHMENT I

(i) *Prohibitions*. All the prohibitions listed in section 9(a)(1) of the Endangered Species Act of 1973 (16 U.S.C. 1538 (a)(1)) shall apply to the Schaus Swallowtail and the Bahama Swallowtail, *Provided*, That adult Schaus Swallowtails (*Papilio aristodemus ponceanus*) may be taken on Key Largo, if the taking is not in [illegible] activity, and if the taking is in accordance with State and local law.

[FR Doc. 75-10475 Filed 4-21-75;8:45 am]

Geological Survey

[30 CFR Parts 250, 251]

OUTER CONTINENTAL SHELF

Oil, Gas and Sulphur Operations; Geological and Geophysical Explorations

Notice is hereby given that, pursuant to the authority vested in the Secretary of the Interior by the Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. 1331-1343), it is proposed to amend 30 CFR 250.97 and to add Part 251 to Title 30, Code of Federal Regulations.

The purpose of the amendment of 30 CFR 250.97 is to specify a definite time when geological and geophysical interpretations, maps and data pertaining to leased lands will be made available for public inspection. The purpose of Part 251 is to prescribe policies, procedures, and requirements for conducting geological and geophysical explorations of the Outer Continental Shelf.

It is also proposed that when Part 251 is adopted, all existing authorizations to conduct geological and geophysical explorations of the Outer Continental Shelf be revoked as follows:

(1) Notice dated September 17, 1953, Outer Continental Shelf, Geological and Geophysical Explorations (Texas) (18 FR 5667 and footnote 1).

(2) Notice dated March 23, 1954, Outer Continental Shelf, Geological and Geophysical Explorations (Louisiana) (19 FR 1730).

(3) Notice dated March 31, 1955, Outer Continental Shelf, Geological and Geophysical Explorations (California) (20 FR 2023).

(4) Notice dated March 27, 1956, Outer Continental Shelf, Geological and Geophysical Exploration (Florida) (21 FR 2129).

(5) Notice dated August 25, 1958, Outer Continental Shelf, Geological and Geophysical Explorations (Alabama) (23 FR 6760).

(6) Notice dated August 5, 1960, Outer Continental Shelf, Geological and Geophysical Explorations (Georgia) (25 FR 7811).

(7) Notice dated September 6, 1960, Outer Continental Shelf, Geological and Geophysical Explorations (Atlantic Coast Area) (25 FR 8759).

(8) Notice dated July 28, 1961, Outer Continental Shelf, Geological and Geophysical Explorations (Pacific Coast Area off Oregon and Washington) (26 FR 6874).

(9) Notice dated March 7, 1964, Outer Continental Shelf, Geological and Geophysical Exploration (Alaska) (29 FR 3369).

(10) Memorandum dated May 14, 1965, from the Director, Geological Survey to the Secretary of the Interior, approved by the Secretary of the Interior on May [illegible] the Area Oil and Gas Supervisor, Gulf of Mexico Area, to approve core drilling on the Continental Slope of the Gulf of Mexico.

(11) Memorandum dated February 16, 1967, from the Director, Geological Survey, to the Secretary of the Interior, approved by the Secretary of the Interior on March 1, 1967, authorizing the Area Oil and Gas Supervisor, Eastern Area, to approve core drilling on the Continental Slope of the Atlantic Ocean.

(12) Notice dated December 11, 1974, Outer Continental Shelf Geological and Geophysical Exploration (39 FR 43562).

These proposed regulations also incorporate the subject matter of draft amendments of 30 CFR 250.38(g), 250.70, 250.71, 250.72, 250.73, and 250.74 appearing in a notice published in the FEDERAL REGISTER on May 16, 1974 (39 FR 17446-17447) pertaining to geological and geophysical data submission and disclosure. On the basis of public hearings held on July 15 and 16, 1974, and comments received, certain changes are incorporated in these proposed regulations.

It is the policy of the Department of the Interior, whenever practicable, to afford the public an opportunity to participate in the rule making process. Accordingly, interested parties may submit written comments, suggestions, or objections with respect to the proposed regulations to the Director, U.S. Geological Survey, National Center, Reston, Virginia 22092, on or before June 6, 1975.

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)), the Department has prepared a draft Environmental Impact Statement on the proposed 30 CFR Part 251. The availability of the statement is being officially announced simultaneously with the publication of this notice. Comments thereon are being invited and will be considered in the preparation of a final Environmental Impact Statement to be published prior to any final decision on the issuance of the proposed regulations.

Dated: April 16, 1975.

ROYSTON C. HUGHES,
Assistant Secretary of the Interior.

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

Part 250 of Title 30 of the Code of Federal Regulations is amended as set forth below:

Section 250.97 is amended to read as follows:

§ 250.97 Public inspection of records.

(a) Geophysical interpretations, maps and data and geological interpretations and maps which are submitted pursuant to the requirements of this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect, or for a period of 10 years following issuance of the lease, whichever is less, unless the Supervisor [illegible] that [illegible] is necessary for the proper development of the field or area.

(b) Geological data which are submitted pursuant to the requirements of this part shall be made available for public inspection within a period of 6 months after the date of submission pursuant to the requirements of this part except that the Supervisor may extend the time for release up to a total of one year after the date of submission.

Part 251 is added to Chapter II of Title 30 of the Code of Federal Regulations to read as follows:

PART 251—GEOLOGICAL AND GEOPHYSICAL EXPLORATION OF THE OUTER CONTINENTAL SHELF

AUTHORITY: Sec. 11, Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462, 469; 43 U.S.C. 1331, 1340).

GENERAL PROVISIONS

§ 251.1 Purpose.

The purpose of the regulations in this part is to prescribe policies, procedures, and requirements for geological and geophysical exploration for mineral resources and scientific research of the Outer Continental Shelf.

§ 251.2 Authority and scope.

(a) The regulations in this part are issued pursuant to Section 11 of the Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462, 469, 43 U.S.C. 1331, 1340).

(b) It is the policy of the Department to encourage geological and geophysical explorations of the Outer Continental Shelf.

(c) Authorization by the Department to engage in such activities conveys no right to a lease and constitutes no commitment by the Government to offer the area covered by the authorization for leasing.

(d) The regulations in this part shall not apply to geological and geophysical explorations conducted on a lease in the Outer Continental Shelf of the United States by or on behalf of the lessee. Those explorations shall be governed by the regulations in Part 250 of this chapter.

(e) The regulations of this part are applicable to permits issued prior to publication of this part, but if there is direct conflict between the express terms of such a permit and these regulations the terms of the permit shall control.

§ 251.3 Definitions.

When used in this part, the following definitions shall apply:

(a) *Director*. The Director of the Geological Survey, United States Department of the Interior.

(b) *Supervisor*. A representative of the Secretary, or any subordinate of such representative acting under his direction, subject to the direction and supervisory authority of the Director, the Chief, Conservation Division, Geological Survey, and the appropriate Conservation Manager, Conservation Division, Geological Survey, authorized and empowered to regulate operations and to perform other duties prescribed in the regulations in this part.

(c) *Person*. A natural person, an association, a State, a political subdivision of a State, or a private, public or municipal corporation.

(d) *Geological explorations for mineral resources*. Operations which utilize geologic and geochemical techniques, including core and test drilling and various bottom sampling methods, to produce information concerning the Outer Continental Shelf. The term does not include explorations for scientific research.

(e) *Geophysical explorations for mineral resources*. Operations which utilize geophysical techniques, including gravity, magnetic and various seismic methods, to produce information concerning the Outer Continental Shelf. The term does not include explorations for scientific research.

(f) *Geological and geophysical explorations for scientific research*. Any investigation conducted for scientific research purposes involving the gathering and analysis of geolcgical or geophysical data of the Outer Continental Shelf, the results of which will be made available to the public.

(g) *Deep stratigraphic test*. Drilling of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters).

(h) *Permit*. The contract or agreement, approved for a specified period of time, under which the permittee acquires the right to conduct (1) geological or geophysical explorations for mineral resources of the Outer Continental Shelf; or (2) scientific research of the Outer Continental Shelf which involves the use of solid or liquid explosives or the penetration of more than 50 feet (15.2 meters) or consolidated rock or a total of 300 feet (91.4 meters) under the conditions at the locations specified in the permit.

(i) *Outer Continental Shelf*. All submerged lands which lie seaward and outside the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29; 43 U.S.C. §§ 1301–1315) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(j) *OCS Order*. A formal numbered order issued by the Supervisor with the prior approval of the Chief, Conservation Division, Geological Survey, that implements the regulations contained in this part or 30 CFR Part 250 of this Chapter and applies to operations in an area or a major portion thereof.

§ 251.4 Requirements for conducting geological and geophysical explorations of the Outer Continental Shelf.

(a) Any person wishing to conduct geological or geophysical explorations for mineral resources of the Outer Continental Shelf must obtain a permit for such exploration from the Supervisor.

(b) Any person desiring to conduct explorations for scientific research on the Outer Continental Shelf is not required to obtain a permit from the Supervisor unless such explorations involve the use of solid or liquid explosives or the penetration of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters).

(c) Agencies of the United States using Federal employees and federally-owned facilities are not required to obtain a permit to conduct geological or geophysical explorations of the Outer Continental Shelf.

(d) Persons conducting scientific research not requiring a permit and agencies of the United States shall, prior to commencing such explorations, file with the Supervisor a notice to the Director which includes:

(1) Identification of the person or agency which will conduct the proposed exploration;

(2) Type of exploration and manner in which it will be conducted;

(3) Location on the Outer Continental Shelf where the exploration will be conducted;

(4) Dates on which the exploration is to be commenced and completed;

(5) The proposed timing and manner in which the results of the exploration will be released to the public or made available through publication; and

(6) A statement that the data and the processed information derived therefrom will not be sold or withheld for exclusive use.

(e) The Director shall be notified immediately, through the Supervisor, of any adverse effects of the exploration on the environment, aquatic life, or other uses of the area in which the exploration was conducted.

§ 251.5 Responsibilities.

Subject to the authority of the Secretary of the Interior, the regulations in this part shall be administered by the Director, through the Chief, Conservation Division of the Geological Survey and the Supervisor.

(a) The Supervisor shall receive and act on applications to conduct geological or geophysical exploration of the Outer Continental Shelf. Permits for exploration involving the use of solid or liquid explosives or for penetration of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters) shall be approved only under conditions established by the Director.

(b) The Supervisor shall not issue any permit until he has found that such exploration will not interfere with or endanger operations under any lease maintained or granted pursuant to the Outer Continental Shelf Lands Act and that such exploration will not be unduly harmful to aquatic life in the area, result in pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(c) The Supervisor shall not approve an application if the applicant has demonstrated an unwillingness to conduct exploration activities in accordance with the terms and conditions of the permit and applicable OCS orders, regulations, and laws.

(d) The Supervisor may, subject to the approval of the Chief, Conservation Division, Geological Survey, issue OCS orders implementing the requirements of the regulations of this part when such implementations apply to an entire area or a major portion thereof.

(e) The Supervisor may issue written or oral orders to govern operations under a specific permit. The Supervisor shall confirm oral orders in writing as promptly as possible.

(f) When any person intending to conduct scientific research for which a permit is not required or any agency of the United States has notified the Supervisor of its desire to conduct explorations of the Outer Continental Shelf, the Supervisor shall inform the person or agency of precautions which the Director considers necessary to assure that the exploration will not interfere with or endanger operations under a lease, cause undue harm to aquatic life, cause pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(g) The Supervisor may consult with any Federal or State agency possessing expertise which he deems useful in formulating permit stipulations and conditions.

(h) The Supervisor is authorized to cooperate with State authorities and to utilize state inspection services for the protection of aquatic life and other values when such services are available.

(i) The Supervisor shall advise the appropriate officials of other bureaus and offices of the Department and other Federal and State agencies of the nature and

location of exploratory activities conducted pursuant to this part which may affect their respective programs and interests.

(j) The Supervisor or his representative may order, either in writing or orally with written confirmation, the suspension of any operation conducted pursuant to a permit issued in accordance with the regulations of this part when in his judgment such operation threatens immediate, serious, and irreparable harm or damage to life, including aquatic life, property, cultural resources, any valuable mineral deposits, or the environment. Such suspension of operations under the permit shall continue until the permittee is notified in writing by the Supervisor that operations may resume.

CONDITIONS FOR ISSUANCE OF PERMITS

§ 251.10 Applications.

(a) Applications for permits to conduct geological or geophysical exploration of the Outer Continental Shelf shall be on a form approved by the Director, Geological Survey. All applications shall include:

(1) Identification of persons or agencies participating in the proposed exploration;

(2) Type of exploration and manner in which it will be conducted;

(3) Location where the exploration will be conducted;

(4) Purpose of conducting such exploration;

(5) Dates on which the exploration will be commenced and completed; and

(6) Such other information as the Supervisor may request of the applicant.

(b) Applications to conduct geological or geophysical explorations of the Outer Continental Shelf must be filed in duplicate with the Supervisor as follows:

(1) For geophysical explorations which do not involve the use of explosives, at least 10 working days before the work for which the permit is sought is scheduled to begin;

(2) For geological explorations (excluding deep stratigraphic tests) or geophysical explorations involving the use of explosives, at least 30 working days before the work for which the permit sought is scheduled to begin; and

(3) For deep stratigraphic tests, at least 90 working days before the work for which the permit is sought is scheduled to begin.

(c) Application filing locations:

(1) Applications to conduct geological and geophysical explorations for oil, gas, and sulphur shall be filed in the following Geological Survey offices:

(i) For areas off the Atlantic Coast—the Area Oil and Gas Supervisor, Eastern Area, Washington, D.C.

(ii) For areas in the Gulf of Mexico—the Area Oil and Gas Supervisor, Gulf of Mexico Area, Metairie, Louisiana.

(iii) For areas off the coast of the States of California, Oregon, and Washington—the Area Oil and Gas Supervisor, Pacific Area, Los Angeles, California.

(iv) For areas off the State of Alaska—the Area Oil and Gas Supervisor, Alaska Area, Anchorage, Alaska.

(2) Applications to conduct geological or geophysical exploration for minerals other than oil, gas, and sulphur shall be filed in the following Geological Survey offices:

(i) For areas off the Atlantic Coast and in the Gulf of Mexico—the Area Mining Supervisor, Eastern Area, Washington, D.C.

(ii) For areas off the States of Alaska, California, Oregon, and Washington—the Area Mining Supervisor, Alaska—Pacific Area, Menlo Park, California.

(3) Applications to conduct scientific research on the Outer Continental Shelf which requires a permit shall be filed with the Area Oil and Gas Supervisor as indicated in paragraph (c)(1) of this section.

§ 251.11 General conditions of permits.

(a) Separate permits for geological and for geophysical explorations will be issued.

(b) Each permit shall authorize the exploration as described in the application, except to the extent that the description is modified by the terms of the permit; and will notify the permittee that it must comply with the terms and conditions of the permit, OCS orders, other orders of the Supervisor, the regulations in this part, and other applicable laws and regulations. Geological and geophysical exportation permits shall be subject to such terms and conditions as the Supervisor deems necessary including, but not limited to, terms and conditions to assure that operations will not:

(1) Interfere with or endanger operations under any lease maintained or granted pursuant to the Outer Continental Shelf Lands Act;

(2) Cause undue harm to aquatic life;

(3) Cause pollution;

(4) Create hazardous or unsafe conditions;

(5) Unreasonably interfere with or harm other uses of the area; or

(6) Disturb any site, structure, or object of historical or archaeological significance.

(c) The permit shall provide for the means by which data will be submitted to Geological Survey.

(d) The permittee shall notify appropriate agencies including the Coast Guard, the Corps of Engineers and other Federal and State agencies designated by the Supervisor prior to commencing explorations.

§ 251.12 General obligations of permittee.

(a) A permittee shall conduct explorations only in compliance with the terms and conditions of the permit, the orders of the Supervisor, the regulations in this part, and all other applicable laws and regulations, and in a manner which will not interfere with or endanger operations under any lease, or unduly harm aquatic life, result in pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(b) Upon the direction of the Supervisor, a permittee authorized to conduct geological or geophysical explorations shall utilize the services of an advisor or consultant qualified to observe and advise and who will observe operations conducted pursuant to the permit and advise the permittee and the Supervisor of any adverse effects of the operations upon the environment, aquatic life, and other uses of the area. The cost of obtaining any non-Federal advisor or consultant shall be paid by the permittee. The permittee shall, on request of the Supervisor, furnish quarters and transportation at no cost, for a Federal representative to inspect operations.

§ 251.13 Core or test drilling.

(a) Permits authorizing geological exploration by means of shallow coring or drilling may be issued by the Supervisor.

(1) Prior to issuing a permit, the Supervisor may require that high resolution seismic data including bathymetric, side-scan sonar and magnetometer data be gathered across any proposed drilling location so as to determine shallow structural detail in the vicinity of the proposed test.

(2) In order to minimize duplicative geological exploration involving penetration of the seabed of the Outer Continental Shelf, the Supervisor may require an applicant to afford all interested persons an opportunity to participate in the program on a cost-sharing basis. The penalty for late participation in such a program shall not be more than 50 percent of the cost to each of original participants. If required to provide for group participation, the applicant shall:

(i) Publish a summary statement of the proposed program in a manner approved by the Supervisor;

(ii) Allow reasonable time, but not less than 30 days from the date of publication, for other persons to consider participation in the program;

(iii) Forward a copy of the published notice(s) to the Supervisor;

(iv) Compute the direct costs to a participant in a geological exploration program by dividing the total costs of the program by the number of participants. Such figure shall be revised when additional (including late) participants join the group; and

(v) Furnish the Supervisor with a complete list of all participants under the permit prior to commencing operations and, on a timely basis, a list of all late participants.

(3) The permittee shall conduct such exploration in a manner which prevents blowouts, prevents release of fluids from stratum into the sea, and prevents communication between separate fluid-bearing strata of oil, gas, or water. The permittee shall utilize appropriate protective measures and devices specified by the Supervisor.

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(b) Permits authorizing geological exploration by means of deep stratigraphic drilling on the Outer Continental Shelf may be issued by the Supervisor only after the Director has approved the drilling plan.

(1) An application to conduct deep stratigraphic drilling shall be accompanied by a drilling plan which shall include:

(i) A description of the drilling rig proposed for use showing the design and major features thereof, including features intended to prevent or control pollution;

(ii) The location of each deep stratigraphic test to be drilled including surface and projected bottom hole location for directionally drilled tests;

(iii) An oil spill contingency plan and a description of all equipment and materials available to the permittee for use in containment and recovery of an oil spill, with a description of the capabilities of such equipment under different sea and weather conditions;

(iv) High resolution seismic data including bathymetric, side-scan sonar and magnetometer data collected across any proposed drilling location so as to permit determination of shallow structural detail in the vicinity of the proposed well, and for stratigraphic wells proposed to depths greater than 1,000 feet (304.8 metres) below the mudline, common depth point seismic data from the area of the proposed test location and interpretations therefrom; and

(v) Such other pertinent information and data as the Director or Supervisor may request.

(2) Before any modification may be made in an approved drilling plan, the proposed modification must be approved by the Director. Any relocation of drillsite exceeding 300 feet (91.4 metres) or redrill of the hole shall have prior approval of the Supervisor.

(3) In order to minimize duplicative geological exploration involving penetration of the seabed of the Outer Continental Shelf, the Supervisor shall require an applicant for a permit to perform deep stratigraphic drilling to afford all interested persons an opportunity to participate in the program on a cost-sharing basis with a penalty for late participation of not more than 100 percent of the cost to each original participant. To provide for group participation, the applicant shall:

(i) Publish a summary statement of the proposed program in a manner approved by the Supervisor;

(ii) Allow reasonable time, but not less than 30 days from the date of publication, for other persons to consider participation in the program;

(iii) Forward a copy of the published notice(s) to the Supervisor;

(iv) Compute the direct cost to a participant in a geological exploration program by dividing the total cost of the program by the number of participants. Such figure shall be revised when additional (including late) participants join the group; and

(v) Furnish the Supervisor with a complete list of all participants under the permit prior to commencing operations and submit, on a timely basis, a list of all late participants.

(c)(1) Prior to any coring or drilling activity, the permittee will conduct studies sufficient to determine the possible existence of any sites, structures, or objects of historical or archaeological significance that may be affected by such an operation, and shall report the findings of the studies to the Supervisor. If any study indicates the possible presence of a cultural resource, a full explanation will be included in the report and the Supervisor shall take appropriate action.

(2) The permittee shall take no action that may result in its disturbance without the prior approval of the Supervisor, but if any cultural resource is accidentally discovered, the permittee shall immediately report the finding to the Supervisor and make every reasonable effort to preserve and protect the cultural resource from damage until the Supervisor has given directions as to its disposition.

(d) All Outer Continental Shelf Regulations relating to drilling operations in Part 250 of this chapter and all OCS Orders relating to the drilling and abandonment of wells apply as appropriate to permits to drill, issued pursuant to this part. Departures from the requirements of OCS Orders shall be permitted as provided for in § 250.12(b) of this chapter.

(e) Bonds. Before a permit authorizing coring or drilling will be issued, the applicant shall furnish to the Bureau of Land Management a corporate security bond of not less than $100,000 conditioned on compliance with the terms of the permit, unless he already maintains with or furnishes to the Bureau of Land Management a bond in the sum of $300,000 conditioned on compliance with the terms of exploration permits issued to him on the Outer Continental Shelf in (1) Gulf of Mexico, (2) along the Pacific Coast, (3) along the Atlantic Coast, or (4) other area of operations, as may be appropriate. The bond furnished or maintained by the applicant will be on a form approved by the Supervisor.

§ 251.14 Reports.

(a) The Director shall be notified immediately, through the Supervisor, of any adverse effects of the exploration on the environment, aquatic life or other uses of the Area in which the exploration was conducted or on any site, structure, or object of historical or archaeological significance.

(b) The permittee shall send interim reports which include a daily log of operations to the Supervisor on a weekly basis.

(c) The permittee shall submit a final report to the Supervisor within 30 days after the completion of any exploration activity. The final report shall contain the following:

(1) A description of the work performed;

(2) Charts, maps, or plats depicting the areas in which the exploration was conducted and specifically identifying the lines over which geophysical traverses were run or the specific locations at which geological explorations were conducted, including a reference sufficient to identify the data produced during each operation;

(3) The dates on which the exploration was performed;

(4) A report of any adverse effects of the exploration on the environment, aquatic life, any lease operations in the area, or other uses of the area in which the exploration was conducted, or on any site, structure or object of historical or archaeological significance.

(5) The data required to be submitted in paragraphs (d) and (e) of this section; and

(6) Such other information as may be specified by the Supervisor.

(d) In addition to the reports required in paragraphs (a), (b), (c) of this section, upon request by the Supervisor, the following geological data and processed information acquired under geological exploration permit shall be submitted to the Supervisor within 30 days after request. The time for submitting processed data may be extended by the Supervisor if the permittee shows that additional time is necessary to complete data processing.

(1) Accurate and complete records of all geological and geochemical data resulting from each drilling operation;

(2) Paleontological reports identifying microscopic fossils by depth (not resulting age interpretations based upon such identification) unless washed samples are maintained by the permittee for paleontological determination and are made available for inspection by the Geological Survey;

(3) Copies of logs or charts of electrical, radioactive, sonic, and other well logging operations;

(4) Analyses of core or bottom samples or a representative cut or split of the core or bottom sample;

(5) Detailed descriptions of any hydrocarbon shows or hazardous conditions encountered during operations, including near losses of well control, abnormal geopressures, and losses of circulation; and

(6) Such other geological and geochemical data and processed information obtained under the permit as may be specified by the Supervisor.

(e) In addition to the reports required in paragraphs (a), (b), and (c) of this section, upon request by the Supervisor, the following geophysical data and processed information acquired under a geophysical exploration permit shall be submitted to the Supervisor within 30 days after request. The time for submitting processed data may be extended by the Supervisor if the permittee shows that additional time is necessary to complete data processing.

(1) Accurate and complete records of each geophysical survey conducted under the exploration permit, including

final location maps of all survey stations; and

(2) All common depth point and high resolution seismic data developed under an exploration permit including the processed information derived therefrom with extraneous signals and interference removed, in a format and quality suitable for interpretive evaluation, reflecting state-of-the-art processing techniques; and other data including, but not limited to, shallow and deep subbottom profiles, bathymetry, side-scan sonar, magnetometer, and bottom profiles; gravity and magnetic; and data from special studies such as from refraction surveys, velocity surveys and domal configuration studies.

§ 251.15 Public availability of records.

Geological and geophysical data, including processed information relating to submerged lands on the Outer Continental Shelf collected pursuant to a permit issued after the publication of these regulations and required to be submitted to the Supervisor under this part, shall be made available for public inspection by the Supervisor as follows:

(a) Geophysical data including processed information—ten years after issuance of a permit to conduct exploration.

(b) Geological data and processed information:

(1) Immediate release through public notice of the discovery during drilling operations of oil shows and environmental hazards on unleased lands when these shows or hazards are judged to be significant by the Director.

(2) Ten years after issuance of the permit to conduct exploration except for deep stratigraphic drilling.

(3) Five years after the date of completion of a test well or 60 calendar days after the issuance of the first Federal lease within 50 geographic miles of the drill site, whichever is earliest, for deep stratigraphic drilling.

CANCELLATION, PENALTIES AND APPEALS

§ 251.20 Revocation and cancellation.

The Supervisor is authorized to suspend or revoke a permit under which the operation is being conducted, or is proposed to be conducted, which in his judgment threatens immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to cultural resources, to valuable mineral deposits, or to the environment, or for noncompliance with applicable laws, regulations, the terms and conditions of the permit, OCS Orders, or any other written order or rule, including orders for submitting reports, well records or logs, and analyses in a timely manner.

§ 251.21 Penalties.

Any person who conducts geological and geophysical exploration of the Outer Continental Shelf without a permit issued under this part or who, having obtained a permit, fails to comply with the terms of the permit will be subject to any civil or criminal remedies which the Secretary chooses to pursue.

§ 251.22 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in Part 290 of this chapter.

[FR Doc.[illegible] Filed 4–21–75;8:45 am]

DEPARTMENT OF TRANSPORTATION

Coast Guard

[33 CFR Part 175]

[CGD 74–159]

NONAPPROVED LIFESAVING DEVICES ON WHITE WATER CANOES AND KAYAKS

Proposed Revocation of Exception; Comment Period Extension

In the February 4, 1975 issue of the Federal Register (40 FR 5167), the Coast Guard published a Notice of Proposed Rulemaking proposing to revoke the exception in 33 CFR 175.17 from Personal Flotation Device (PFD) requirements presently allowed for operators of white water canoes and kayaks. The notice provided that all written comments received before April 17, 1975 would be considered before action would be taken on the proposal.

The purpose of this notice is to extend the comment period to May 31, 1975 in order to give the public additional time to submit written data, views, and arguments concerning the notice.

All communications received before May 31, 1975 will be considered before action is taken on the proposed revocation.

(Sec. 5 of the Federal Boat Safety Act of 1971 (46 U.S.C. 1454); 49 CFR 1.46(o)(1))

Dated: April 16, 1975.

A. F. FUGARO,
Captain, U.S. Coast Guard, Acting Chief, Office of Boating Safety.

[FR Doc.75–10470 Filed 4–21–75;8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 450]

[FRL 361–7]

EFFLUENT GUIDELINES AND STANDARDS

Pretreatment Standards for Oil and Grease; Request for Public Comments

During the past several months EPA has proposed pretreatment standards for existing sources which discharge into publicly owned treatment works and promulgated pretreatment standards for new sources which discharge into publicly owned treatment works, pursuant to section 307 (b) and (c) of the Federal Water Pollution Control Act, 33 U.S.C. section 1317.

Internal review of these regulations by EPA has led to the conclusion that additional consideration should be given to the question of the proper pretreatment standard for the discharge of oil and grease for all industrial categories. The Agency has compiled additional data concerning this question. This data is summarized and analyzed in a document [illegible]

These data appear to indicate that no pretreatment limitation should be placed on the discharge of oil and grease of an animal or vegetable origin where such wastes are essentially free from petroleum or mineral based oil and greases. On the other hand, where the oil and grease is known to be derived from petroleum or mineral sources or where the source is unknown a pretreatment standard limitation of 100 mg/l on oil and grease appears to be most appropriate. The Agency is presently considering inclusion of these limitations in pretreatment standards for all industrial categories. However before doing so, the Agency desires to hear the views of publicly owned treatment plant operators, industrial users and all other interested parties.

Information concerning the data which supports the above conclusions and pertinent definitions and methodology are contained in the above mentioned document. Copies of this document are available through the Office of Public Affairs, Environmental Protection Agency, Washington D.C. 20460, Attention: Ms. Ruth Brown, A-107.

Interested persons may submit written comments in triplicate to Ms. Ruth Brown, Office of Public Affairs, at the above address. Comments on all aspects of this request for public participation are solicited. In the event comments are in the nature of criticisms as to the adequacy of data which is available, or which may be relied upon by the Agency, comments should identify and, if possible, provide any additional data which may be available and should indicate why such data is essential to the development of the regulations.

In the event comments address the approach taken by the Agency in establishing pretreatment standards for existing sources, EPA solicits suggestions as to what alternative approach should be taken and why and how this alternative better satisfies the detailed requirements of section 307(b) of the Act.

A copy of all public comments will be available for inspection and copying at the EPA Freedom of Information Center, Room 204, West Tower, Waterside Mall, 401 M Street SW., Washington, D.C. 20460. The EPA information regulation, 40 CFR 2, provides that a reasonable fee may be charged for copying.

All comments received on or before May 22, 1974, will be considered.

Date: April 15, 1975.

RUSSELL E. TRAIN,
Administrator.

[FR Doc.75–10478 Filed 4–21–75;8:45 am]

Attachment J

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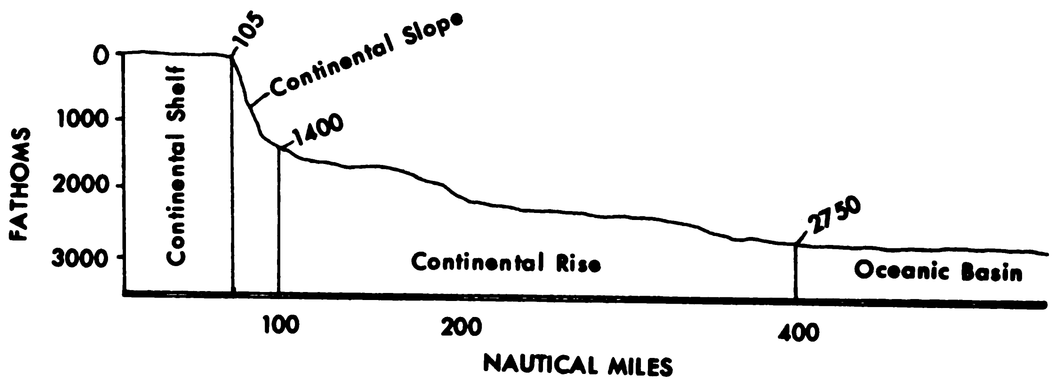
Attachment K

Alluvium----The detrital deposits eroded, transported, and deposited by streams; an important constituent of shelf deposits.
anadromous----A form of life cycle among fishes in which maturity is attainted in the ocean, and the adults ascend streams and rivers to spawn in fresh water. Salmon and shad are two examples.
bathyal----Pertaining to ocean depths between 100 and 2,000 fathoms (180 and 3,700 meters); also to the ocean bottom between those depths, some times identical with the continental slope environment.
bathymetry----The science of measuring ocean depths in order to determine the sea floor topography.
bight----A concavity in the coastline which forms a large open bay.
biomass----(also called standing crop, standing stock, live-weight). The amount of living matter per unit of water surface or volume expressed in weight units.
clastic----A rock composed principally of detritus transported mechnically into its place of final deposition. Sandstones and shales are the commonest clastics. Limestones are not clastic rocks unless formed of particles derived from pre-existing limestone.
Continental margin provinces----Type profile off northeastern United States. This profile is representative of the sector from Georges Bank to Cape Hatteras, however vertical exaggeration is extreme.



demersal--- Fishes which live on or near the ocean bottom.
detritus----Any loose material produced directly from rock disintegration.
diapir fold----Anticlines in which a mobile core (salt, shale, ect.) has either upwarped overlying rock strata (non-piercement) or actually broken through the overlying beds (piercement).
dip----The angle at which the rock structure is inclined with a horizontal plane.

1/ Most of these definitions exerpted from U.S. Naval Oceanographic Office, Special Publication SP-35, Glossary of Oceanographic Terms. 2nd Ed., 1966.

epicenter----The point on the earth's surface directly above the focus of an earthquake.

evaporite----A rock composed of minerals that have been precipitated from solutions concentrated by the evaporation of solvents. Examples: rock salt, gypsum, anhydrite.

focus----In seismology, the source of a given set of elastic waves; the true center of an earthquake.

geomorphology----That branch of both geography and geology which deals with the form of the earth, the general configuration of its surface, and the changes that take place in the evolution of land forms.

geosyncline----A large generally linear subsident trough in which many thousands of feet of sediments are accumulating or have accumulated. Deep oceanic trenches paralleling island arcs are considered to be developing geosynclines.

gyre----A closed circulatory system, but larger than a whirlpool or eddy.

holoplankton----(or permanent plankton). Organisms living their complete life cycle in the floating state.

intertidal zone----(also called littoral zone). Generally considered to be the zone between mean high water and mean low water levels.

isopleth---A line of equal or constant value of a given quantity with respect to either space or time, e.g. isobar (equal pressure), isobath (equal water depth), isopach (equal thickness of rock layer), isotherm (equal temperature).

lenticular----In the shape of a double convex lens. Applied to commonly occurring lens-shaped sediment or rock bodies of all sizes. Also applied to clouds that attain this shape in the process of dissipation.

littoral current----(longshore current). A water current caused by wave action, that sets parallel to the shore, usually in the nearshore region within the breaker zone.

low energy environment----A region characterized by a general lack of wave or current motion, permitting the settling and accumulation of very fine-grained sediment (silt and clay).

magma----Mobile rock material generated within the earth from which igneous is derived by solidification. When extruded it is called lava.

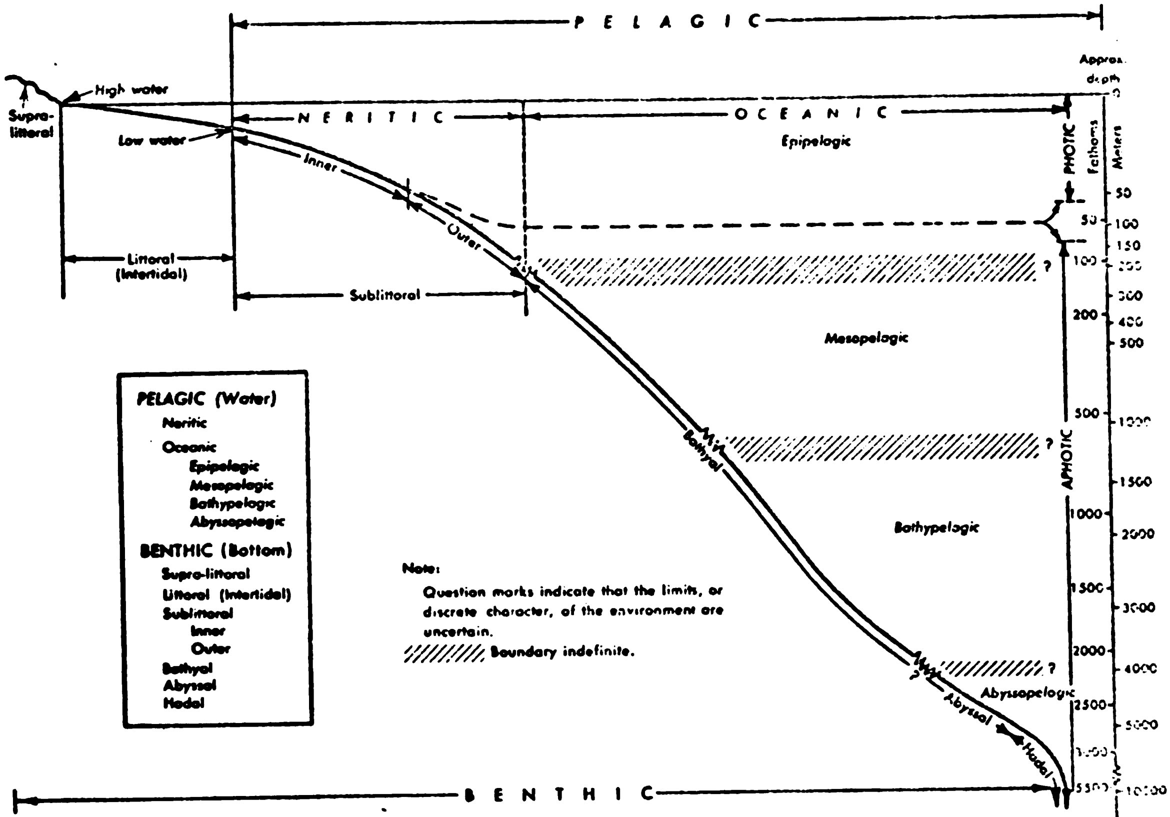
marsh bar----A narrow ridge of sand at the edge of a marsh undergoing wave attack.

meroplankton----Chiefly the floating developmental stages (eggs and larvae) of the benthos and nekton. These forms are especially abundant in neritic waters.

metamorphic rock----Rocks which have undergone structural and mineralogical changes, such as recrystallization, in response to marked changes of temperature, pressure, and chemical environment.

nekton----Those animals of the pelagic division that are active swimmers, such as most of the adult squids, fishes, and marine mammals.

pelagic division----A primary division of the sea which includes the whole mass of water. The division is made up of the neritic province which includes the water shallower than 100 fathoms (200 meters), and the oceanic province which includes that water deeper than 100 fathoms.



CLASSIFICATION OF MARINE ENVIRONMENTS

phytoplankton----The plant forms of plankton. They are the basic synthesizers of organic matter (by photosynthesis) in the pelagic division. The most abundant of the phytoplankton are the diatoms.

plankton----The passively drifting or weakly swimming organisms in marine and fresh waters. Members of this group range in size from microscopic plants to jellyfishes measuring up to 6 feet across the bell, and included the eggs and larval stages of the nekton and benthos.

primary production----(or gross primary production, primary productivity). The amount of organic matter synthesized by organisms from inorganic substances in unit time in a unit volume of water or in a column of water of unit area cross section and extending from the surface to the bottom.

refraction----The process in which the direction of energy propagation is changed as the result of a change in density within the propagating medium, or as the energy passes through the interface representing a desnity discontinuity between two media.

regressive----Applied to bodies of water and sediments deposited therein during withdrawal of the water and/or emergency of the land.

seismic reflection----The measurements, and recording in wave form, of the travel time of acoustic energy reflected back to detectors from rock or sediment layers which have different elastic wave velocities.

silt----An unconsolidated sediment whose particles range in size from 0.0039 to 0.00625 millimeter in diameter (between clay and sand sizes).

slump----(or slide). The slippage or sliding of a mass of unconsolidated sediment down a submarine or subaqueous slope. Slumps occur frequently at the heads or along the sides of submarine canyons. The sediments usually moves as a unit mass initially but often becomes a turbidity flow. It may be triggered by any small or large earth shock.

stratigraphy----The branch of geology which treats of the formation, composition, sequence, and correlation of layered or bedded rocks.

stratum----A single sedimentary bed or layer of generally homogenous rock, independent of thickness.

syncline----A fold or arch of rock in which the strata dip inward toward the plane of the axis.

synclinorium----A broad regional syncline on which are superimposed minor folds.

tectonics----The study of origin and development of the broad structural features of the earth.

thermocline----A vertical negative temperature gradient in some layer of a body of water, which is appreciable greater than the gradients above and below it; also a layer in which such a gradient occurs. The principal thermoclines in the ocean are either seasonal, due to heating of the surface water in summer, or permanent.

tsunami----(or tunami, tidal wave, seismic sea wave). A long-period sea wave produced by a submarine earthquake or volcanic eruption. It may travel unnoticed across the ocean for thousands of miles from its point of origin and builds up to great heights over shoal water.

turbidity----Reduced water clarity resulting from the presence of suspended matter. Water is considered turbid when its load of suspended matter is visibly conspicuous, but all waters contain some suspended matter and therefore are turbid.

upwelling----The process by which water rises from a lower to a higher depth, usually as a result of divergence and offshore currents. Upwelling is most prominent where persistent wind blows parallel to a coastline so that the resultant wind-driven current sets away from the coast.

zooplankton----The animal forms of plankton. They include various crustaceans, such as copepods and euphausiids, jellyfishes, certain protozoans, worms, mollusks, and the eggs and larvae of benthic and nektonic animals. They are the principal consumers of the phytoplankton and, in turn, are the principal food for a large number of squids, fishes, and baleen whales.